Federal Energy
Regulatory
Commission

Office of
Energy Projects

March 2013

Downeast LNG, Inc.
Downeast Pipeline, LLC.

Docket No. CP07-52-000
Docket Nos. CP07-53-000
CP07-53-001

Downeast LNG Project

Supplemental Draft Environmental Impact Statement

Cooperating Agencies:

U.S. Department
Of Transportation

Washington, DC 20426

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas 1
Downeast LNG, Inc.
Downeast Pipeline, LLC
Docket Nos. CP07-52-000,
CP07-53-000, CP07-53-001

TO THE PARTY ADDRESSED:

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared a Supplemental Draft Environmental Impact Statement (EIS) for the Downeast LNG Project, proposed by Downeast LNG, Inc. and Downeast Pipeline, LLC (hereafter collectively referred to as Downeast) in the above-referenced dockets. Downeast requests authorization to construct and operate a new liquefied natural gas (LNG) terminal, natural gas pipeline, and associated facilities in Washington County, Maine. The Downeast LNG Project would provide about 500 million cubic feet per day of imported natural gas to the New England region.

The Commission previously issued a draft EIS for this project in May 2009. Since then the U.S. Department of Transportation (DOT) has issued clarifications on its Title 49 of the Code of Federal Regulations, Part 193 (Part 193), which are relevant to the proposed Downeast LNG Project. In October 2011, DOT issued final decisions approving specific alternative models for use in complying with these federal safety standards. Downeast filed information with the FERC as required by the latest regulations in October and November 2012. In 2010, the U.S. Coast Guard (Coast Guard) revised its regulations in Title 33, CFR, Part 127 on the process used to examine the suitability of the waterway for LNG carrier transits. In 2011, the U.S. Coast Guard also updated Navigation and Vessel Inspection Circular 01-2011, "Guidance Related to Waterfront LNG Facilities." In 2012, the U.S. Department of Energy (DOE) released the report "Liquefied Natural Gas Safety Research Report to Congress" detailing the results of research conducted by Sandia National Laboratories on intentional breaches of LNG carrier cargo tanks and the resulting LNG spills on water.

Based on the new information from the DOT, DOE, Coast Guard, and Downeast, FERC staff revised the reliability and safety analysis of the LNG terminal and carrier transit that was presented in the May 2009 draft EIS and prepared this Supplemental draft EIS. This document presents FERC staff's: technical review of the proposed facility's preliminary design; siting analysis, prepared with the cooperation of the DOT; and conclusions on the waterway suitability based on input from the Coast Guard. The DOT participated as a cooperating agency in the preparation of this document.

We[1] mailed copies of the Supplemental draft EIS to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; potentially affected landowners and other interested individuals and groups; newspapers and libraries in the project area; and parties to this proceeding. Paper copy versions of this Supplemental draft EIS were mailed to those specifically requesting them; all others received a CD version. In addition, the Supplement is available for public viewing on the FERC's website (www.ferc.gov) using the eLibrary link. A limited number of copies are available for distribution and public inspection at:

Federal Energy Regulatory Commission
Public Reference Room
888 First Street NE, Room 2A
Washington, DC 20426
(202) 502-8371

Any person wishing to comment on the Supplemental draft EIS may do so. If you previously filed comments on the 2009 draft EIS, it is not necessary to re-submit them. All the comments on the 2009 draft EIS, along with any comments on the Supplemental draft EIS, will be addressed in the final EIS. To ensure consideration of your comments on the Supplemental draft EIS, it is important that the Commission receive your comments before **May 20, 2013**.

For your convenience, there are three methods you can use to submit your comments to the Commission. In all instances, please reference the project docket number (CP07-52-000) with your submission. The Commission encourages electronic filing of comments and has expert staff available to assist you at (202) 502-8258 or efiling@ferc.gov.

1) You can file your comments electronically using the eComment feature on the Commission's website (www.ferc.gov) under the link to Documents and Filings. This is an easy method for submitting brief, text-only comments on a project;

2) You can file your comments electronically by using the eFiling feature on the Commission's website (www.ferc.gov) under the link to Documents and Filings. With eFiling, you can provide comments in a variety of formats by attaching them as a file with your submission. New eFiling users must first

[1] "We," "us," and "our" refer to the environmental staff of the FERC's Office of Energy Projects.

create an account by clicking on "eRegister." If you are filing a comment on a particular project, please select "Comment on a Filing" as the filing type; or

3) You can file a paper copy of your comments by mailing them to the following address:

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR Part 385.214).[2] Only intervenors have the right to seek rehearing of the Commission's decision. The Commission grants affected landowners and others with environmental concerns intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which no other party can adequately represent. **Simply filing environmental comments will not give you intervenor status, but you do not need intervenor status to have your comments considered.**

Questions?

Additional information about the project is available from the Commission's Office of External Affairs, at **(866) 208-FERC,** or on the FERC (www.ferc.gov) using the eLibrary link. Click on the eLibrary link, click on "General Search," and enter the docket number excluding the last three digits in the Docket Number field (i.e., CP07-52). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnline Support@ferc.gov or toll free at (866) 208-3676; for TTY, contact (202) 502-8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to www.ferc.gov/esubscribenow.htm.

Kimberly D. Bose
Secretary

[2] See the previous discussion on the methods for filing comments. If you have previously filed a motion to intervene in the proceeding, it is not necessary to re-submit an additional request.

EXECUTIVE SUMMARY

On December 22, 2006, Downeast LNG, Inc. and Downeast Pipeline, LLC (collectively referred to as Downeast) filed applications with the Federal Energy Regulatory Commission (FERC or Commission) under Section 3(a) and Section 7(c) of the Natural Gas Act to construct, operate, and maintain a liquefied natural gas (LNG) import facility, associated sendout pipeline, and various ancillary facilities. On May 15, 2009, FERC staff issued a draft environmental impact statement (EIS) which addressed the potential effects of construction and operation of Downeast's proposed project, referred to as the Downeast LNG Project.[1]

The Commission's regulations under Title 18, Code of Federal Regulations (CFR), Part 380 require Downeast to identify how the proposed design would comply with the siting requirements of the U.S. Department of Transportation's (DOT) requirements under Title 49, CFR, Part 193 (Part 193). In October 2011, DOT issued final decisions, which are relevant to the Downeast LNG Project, approving specific alternative models for use in the exclusion zone analysis specified by Part 193. In response to the DOT's final decisions, Downeast filed information with the FERC in October and November 2012. In addition, new studies and regulations relating to the review of LNG carrier transit along the waterway were released after issuance of the May 2009 draft EIS. In 2010, the U.S. Coast Guard (Coast Guard) revised its regulations in Title 33, CFR, Part 127 on the process used to examine the suitability of the waterway for LNG carrier transits. In 2011, the Coast Guard also updated Navigation and Vessel Inspection Circular 01-2011, "Guidance Related to Waterfront LNG Facilities." In 2012, the U.S. Department of Energy (DOE) released the report "Liquefied Natural Gas Safety Research Report to Congress" detailing the results of research conducted by Sandia National Laboratories on intentional breaches of LNG carrier cargo tanks and the resulting LNG spills on water.

Based on the new information from the DOT, DOE, Coast Guard, and Downeast, FERC staff revised the reliability and safety analysis of the LNG terminal and carrier transit that was presented in the May 2009 draft EIS and prepared this Supplemental draft EIS. This document presents FERC staff's: technical review of the proposed facility's preliminary design; siting analysis, prepared with the cooperation of the DOT; and conclusions on the waterway suitability based on input from the Coast Guard. The conclusions and recommendations presented in the Supplement are those of the FERC environmental staff for the revised reliability and safety analysis.

FERC staff concluded that the preliminary engineering design would be acceptable provided: the mitigation measures relating to the reliability, operability, and safety of the

[1] The draft EIS can be found on FERC's eLibrary under Docket No. CP07-52 under accession number 20090514-4000.

proposed design are addressed by Downeast; and that the facility be subject to the Commission's construction and operational inspection program. FERC staff, with the DOT acting as a cooperating agency, concluded that the site would meet the thermal radiation exclusion zone requirements, but that the vapor dispersion analysis presented by Downeast indicates the site would not meet the requirements of Part 193. Based on its analysis of the LNG carrier transit, the Coast Guard recommended that the waterway along the proposed carrier transit route would be suitable for the type and frequency of LNG marine traffic associated with this proposed project, contingent on the implementation of measures to responsibly manage the maritime safety and security risks.

Comments received on the Supplement will be addressed in a final EIS, along with all comments previously received on the 2009 draft EIS. The final EIS will be used by the FERC in its decision-making process to determine whether or not to authorize the project.

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2004 Sandia Report	Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas Spill Over Water, December 2004
2008 Sandia Report	Breach and Safety Analysis of Spills Over Water from Large Liquefied Natural Gas Carriers, May 2008
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BLEVE	boiling-liquid-expanding-vapor explosion
BOG	boil-off gas
Btu/ft^2-hr	British thermal units per square foot per hour
CEII	critical energy infrastructure information
CFR	Code of Federal Regulations
COTP	Coast Guard Captain of the Port
DCS	Distributed Control System
DOE	United States Department of Energy
DOT	United States Department of Transportation
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
ERP	emergency response plan
ESD	emergency shutdown
FEED	front-end engineering design
GAO	United States Government Accountability Office
gpm	gallons per minute
HAZOP	hazard and operability review
HP	high pressure
HVAC	heating, ventilation, and air conditioning
IMO	International Maritime Organization
ISA	International Society for Automation
ISPS Code	International Ship and Port Facility Security Code
kW/m^2	kiloWatts per square meter
LFL	lower flammability limit
LNG	liquefied natural gas

LNG Working Group	Passamaquoddy Bay/Down East Sub-Committee of the Area Maritime Security Committee
LOI	Letter of Intent
LOR	Letter of Recommendation
LOR Analysis	Letter of Recommendation Analysis
m^2	meters squared
m^3	meters cubed
m/s	meter per second
MAWP	maximum allowable working pressure
MDMT	minimum design metal temperature
mph	miles per hour
MTSA	Maritime Transportation Security Act
NEPA	National Environmental Policy Act of 1969
NFPA 59A	National Fire Protection Association Standard 59A: Standard for the Production, Storage, and Handling Of Liquefied Natural Gas
NOI	Notice of Intent
NVIC	Navigation and Vessel Inspection Circular
OEP	Office of Energy Projects
OSHA	Occupational Safety and Health Administration
P&IDs	piping and instrumentaion diagrams
PAWSA	Ports and Waterways Safety Assessment
PFDs	process flow diagrams
psi	pounds per square inch
PSM	Title 29, Code of Federal Regulations, Section 1910.119: Process Safety Management of Highly Hazardous Chemicals, Explosives and Blasting Agents
RPT	rapid phase transition
Sandia	Sandia National Laboratories
SCV	submerged combustion vaporizer
Secretary	Secretary of the Commission
SIS	Safety Instrumented System
SOLAS	International Convention for the Safety of Life at Sea
Supplement	Supplemental Draft Environmental Impact Statement
TMP	Transit Management Plan
UFL	upper flammability limit
%-vol	percent by volume

VTS	vessel traffic system
WSA	Waterway Suitability Assessment
WSR	Waterway Suitability Report

A. INTRODUCTION AND PROPOSED ACTION

1.0 Introduction

On December 22, 2006, Downeast LNG, Inc. and Downeast Pipeline, LLC (collectively referred to as Downeast) filed applications with the Federal Energy Regulatory Commission (FERC or Commission) under Section 3(a) and Section 7(c) of the Natural Gas Act to construct, operate, and maintain a liquefied natural gas (LNG) import facility, associated sendout pipeline, and various ancillary facilities. On January 16, 2008, Downeast filed an amendment to its Section 7(c) application to modify the proposed pipeline route and avoid crossing the Moosehorn National Wildlife Refuge, owned and managed by the U.S. Fish and Wildlife Service. On May 15, 2009, we[1] issued a draft environmental impact statement (EIS), which addressed the potential effects of construction and operation of Downeast's proposed project, referred to as the Downeast LNG Project. The draft EIS included a detailed description of the proposed action, alternatives, and potential environmental impacts. The draft EIS can be found on FERC's eLibrary under Docket No. CP07-52.[2]

Since the draft EIS was issued in May 2009, the U.S. Department of Transportation (DOT) has issued clarifications on its Title 49 of the Code of Federal Regulations, Part 193 (49 CFR 193), which are relevant to Downeast's proposed LNG facility. In October 2011, the DOT issued final decisions approving specific alternative models for use in complying with these federal safety standards.

We prepared this Supplemental draft EIS (Supplement) for the Downeast LNG Project consisting of a revised reliability and safety analysis of the LNG terminal and carrier transit. This analysis uses the compliance information Downeast filed with the FERC regarding 49 CFR 193 and the DOT's approved models for use in complying with these safety standards. The 2009 draft EIS addresses other resource areas. No changes to the project have occurred that affect that analysis; therefore, those resource areas are not included in this Supplement. The reliability and safety analysis is specifically being revised in response to the DOT clarifications. Comments received on this Supplement will be addressed in a final EIS, along with all comments previously received on the 2009 draft EIS. The final EIS will be used by the FERC in its decision-making process to determine whether or not to authorize the project.

[1] "We," "us," and "our" refer to the environmental staff of the FERC's Office of Energy Projects.

[2] Found on FERC's e-library under accession number 20090514-4000.

2.0 Purpose and Need

Downeast's stated purpose of the project is to establish an LNG marine terminal in New England capable of receiving, storing, and regasifying imported LNG from LNG vessels at an average sendout rate of 500 million cubic feet per day. Downeast conducted a non-binding open season that commenced on November 3, 2008 and concluded on December 2, 2008 to determine the level of interest in the services the terminal would provide. Downeast's affiliate, Downeast LNG Trading, LLC, submitted the only bid through the open season process for 500 million cubic feet per day of firm transportation service.

Under section 3 of the Natural Gas Act, the Commission grants authorization for proposed LNG import terminals after first determining whether proposed facilities are in the public interest. Under section 7 of the Natural Gas Act, the Commission determines whether interstate natural gas transportation facilities are in the public convenience and necessity and, if so, grants a Certificate to construct and operate them. The Commission bases its decision on technical competence, financing, rates, market demand, gas supply, environmental impact, long-term feasibility, and other issues concerning a proposed project.

3.0 Public Review and Comment

On January 25, 2006, FERC granted Downeast's request to utilize the pre-filing review process and assigned a pre-filing docket number (PF06-13-000). The purpose of the pre-filing process is to encourage the early involvement of interested stakeholders, facilitate interagency cooperation, and identify and resolve issues and concerns before an application is formally filed with the Commission.

On March 13, 2006, the FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Proposed Downeast LNG Project, Request for Comments on Environmental Issues, and Notice of a Joint Public Scoping Meeting* (NOI). On March 28, 2006, the FERC and the U.S. Coast Guard conducted a joint public scoping meeting in Robbinston, Maine to provide an opportunity for the public to learn more about the proposed project and to provide comments on environmental issues to be addressed in the draft EIS. On September 18, 2006; December 1, 2006; and February 13, 2008, the FERC issued Supplemental NOIs[3]. In addition, the FERC staff conducted agency consultations and participated in interagency meetings.

[3] The Supplemental NOIs were issued to describe two additional natural gas sendout pipeline routes that had been identified (September 18, 2006); to describe potential Maritimes & Northeast Pipeline L.L.C. downstream expansion facilities (December 1, 2006); and to describe the modification of the proposed natural gas sendout pipeline route to avoid crossing the Moosehorn National Wildlife Refuge (February 13, 2008).

On May 15, 2009, the FERC issued the draft EIS for the Downeast LNG Project and filed it with the U.S. Environmental Protection Agency (EPA). A formal notice was published in the Federal Register on May 26, 2009 (74 FR 24846) announcing that the draft EIS was available and had been mailed to individuals and organizations on the distribution list prepared for the project. Issues identified during the public notice and scoping process discussed above, were addressed in the 2009 draft EIS. In accordance with the Council on Environmental Quality's regulations for implementing the National Environmental Policy Act (NEPA), the public was allowed 45 days to comment on the 2009 draft EIS. The FERC also conducted a public comment meeting on June 16, 2009. All comments received on the draft EIS will be addressed in the final EIS. In addition, all comments received on this Supplement will be addressed in the final EIS. With this Supplement, we are specifically requesting comments on the revised reliability and safety analysis.

4.0 Proposed Facilities

Downeast proposes to construct and operate a new LNG import, storage, and vaporization terminal on the south side of Mill Cove, in Robbinston, Maine, slightly south of the confluence of Passamaquoddy Bay and the St. Croix River between the towns of Eastport, Perry, and Calais, Maine. In addition, Downeast proposes to construct and operate a new 29.8-mile-long, 30-inch-diameter natural gas sendout pipeline extending from the LNG terminal to the existing Maritimes & Northeast Pipeline L.L.C. system at the Baileyville Compressor Station. Figure 1 shows the general location of the project. Detailed pipeline route maps are included in Appendix E of the 2009 draft EIS. Figures showing the waterway for LNG marine traffic are provided in Appendix F of the 2009 draft EIS. The project would consist of the following facilities:

- a new marine terminal that would include a 3,862-foot-long pier with a single berth and vessel mooring system, intended to handle LNG vessels ranging from 70,000 to 165,000 cubic meters in capacity, with future expansion capabilities to handle vessels with 220,000 cubic meters of cargo capacity;
- two full-containment LNG storage tanks, each with a nominal usable storage capacity of 160,000 cubic meters;
- LNG vaporization and processing equipment;
- piping, ancillary buildings, safety systems, and other support facilities;
- three vapor fences around the LNG terminal;
- a 29.8-mile-long, 30-inch-diameter underground natural gas pipeline;
- natural gas metering facilities located at the LNG terminal site; and
- various ancillary facilities including pigging[4] facilities and three mainline block valves.

[4] A "pig" is a tool for cleaning and inspecting the inside of a pipeline.

The project would involve the transit of LNG vessels through both U.S. and Canadian waters to and from the LNG terminal in Robbinston, Maine. The intended vessel transit routes include the waters of the Gulf of Maine, Bay of Fundy, Grand Manan Channel, Head Harbor Passage, Friar Roads, Western Passage, and Passamaquoddy Bay.

Since issuance of the 2009 draft EIS, Downeast revised its project design to include three sets of vapor fences. The vapor fences would be made of impermeable Galvalume panels and would act as a barrier for the LNG. A 20-foot-tall fence would be installed adjacent to the vaporization equipment and to the north of the northernmost LNG storage tank. A 25-foot-tall fence would be installed along the west and south side of the property between the LNG process equipment and the property lines. A 30-foot-tall fence would be installed along the northern, western, and southern property lines. Section 4.12.5 further describes these fences.

B. ENVIRONMENTAL ANALYSIS

4.12 Reliability and Safety Analysis

4.12.1 Regulatory Agencies

Three federal agencies share regulatory authority over the siting, design, construction and operation of LNG import terminals: the Coast Guard, the DOT, and the FERC. The Coast Guard regulates the safety of an LNG facility's marine transfer area and LNG marine traffic, and regulates security plans for the entire LNG facility and LNG marine traffic. The DOT establishes federal safety standards for siting, construction, operation, and maintenance of onshore LNG facilities, as well as for the siting of marine cargo transfer systems at waterfront LNG plants. Those standards are codified in 49 CFR 193. Under the Natural Gas Act and delegated authority from the U.S. Department of Energy (DOE), the FERC authorizes the siting and construction of LNG import and export facilities.

In 1985, the FERC and DOT entered into a Memorandum of Understanding regarding the execution of each agency's respective statutory responsibilities to ensure the safe siting and operation of LNG facilities. In addition to FERC's existing ability to impose requirements to ensure or enhance the operational reliability of LNG facilities, the Memorandum of Understanding specified that FERC may, with appropriate consultation with DOT, impose more stringent safety requirements than those in Part 193.

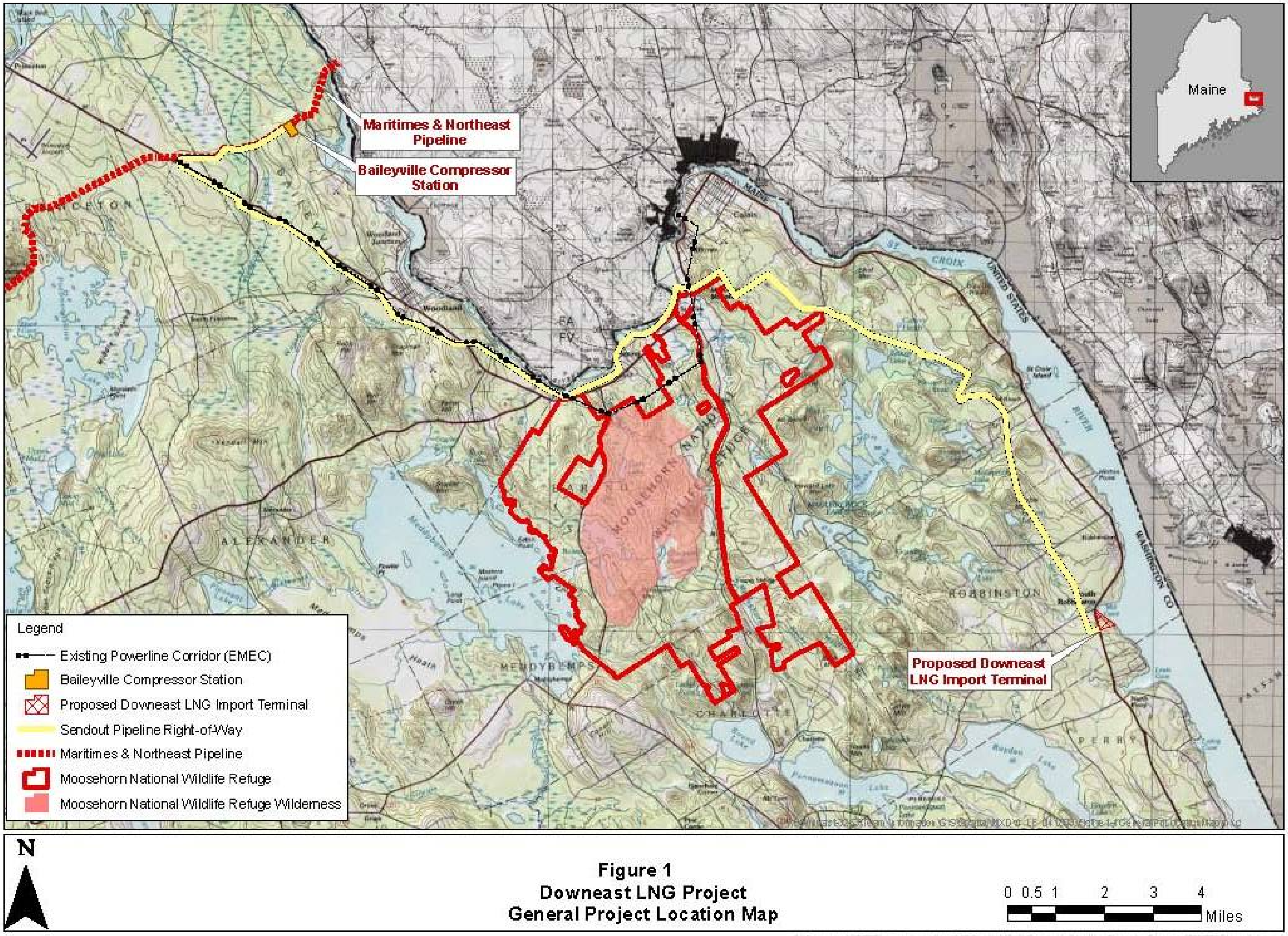


Figure 1
Downeast LNG Project
General Project Location Map

In February 2004, the Coast Guard, DOT, and FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals, including terminal facilities and tanker operations, and maximizing the exchange of information related to the safety and security aspects of the LNG facilities and related marine operations. Under the Interagency Agreement, the FERC is the lead federal agency responsible for the preparation of the analysis required under NEPA for impacts associated with terminal construction and operation. The DOT and Coast Guard participate as cooperating agencies and assist in assessing any mitigation measures that may become conditions of approval for any project.

As part of the review required for a FERC authorization, Commission staff must ensure that all proposed facilities operate safely and securely and are designed in accordance with the applicable requirements set forth in the DOT regulations in 49 CFR 193. The design information must be filed in the application to the Commission as specified by Title 18 CFR 380.12 (m) and (o). The level of detail necessary for this submittal requires the project sponsor to perform substantial front-end engineering of the complete facility. The design information is required to be site-specific and developed to the extent that further detailed design would not result in changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs which we considered during our review process.

The following sections contain the conclusions of our reliability and safety analysis and incorporate comments of the DOT and the Coast Guard as cooperating agencies. In accordance with the working arrangements allowed by the 1985 Memorandum of Understanding, the DOT reviewed our analysis of the applicant’s compliance with the requirements in Part 193, as well as our recommended mitigation measures, and indicated it has no objections at this time. In accordance with 33 CFR 127, the Coast Guard provided FERC with a Letter of Recommendation (LOR) regarding the suitability of the waterway for LNG carrier traffic. Section 4.12.7 includes the results of the Coast Guard’s review on waterway suitability.

4.12.2 Hazards

The principal hazards associated with the storage and vaporization of LNG result from loss of containment, vapor dispersion characteristics, flammability, and the ability to produce damaging overpressures. A loss of the containment provided by storage tanks or process piping would result in the formation of flammable vapor near the release location, as well as near LNG that pooled. Releases occurring in the presence of an ignition source would most likely result in a fire located at the vapor source. A spill without ignition would form a vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limits or encountered an ignition source. In some instances, ignition of a vapor cloud may produce damaging overpressures. These hazards are described in more detail below.

Loss of Containment

LNG would be stored on-site at atmospheric pressure and at a cryogenic temperature of approximately -260 degrees Fahrenheit (°F). Loss of containment of LNG could lead to the release of both liquid and vapor into the immediate area. Exposure to either cold liquid or vapor could cause freeze burns and, depending on the length of exposure, more serious injury or death. However, spills would be contained within the terminal and the cold state of these releases would be greatly limited due to the continuous mixing with the warmer air. The cold temperatures from the release would not present a hazard to any person outside the terminal.

LNG is a cryogenic liquid that quickly cools any materials contacted by the liquid on release, causing extreme thermal stress in materials not specifically designed for such conditions. These thermal stresses could subsequently subject the material to brittleness, fracture, or other loss of tensile strength. These temperatures, however, would be accounted for in the design of equipment and structural supports, and would not be substantially different from the hazards associated with the storage and transportation of liquid oxygen (-296ºF) or several other cryogenic liquids that have been routinely produced and transported in the United States.

A rapid phase transition (RPT) can occur when a cryogenic liquid is spilled onto water and changes from liquid to gas, virtually instantaneously. Unlike an explosion that releases energy and combustion products from a chemical reaction, an RPT is the result of heat transferred to the liquid inducing a change to the vapor state. RPTs have been observed during LNG test spills onto water. In some test cases, the overpressures generated were strong enough to damage test equipment in the immediate vicinity of the LNG release point. The sizes of the overpressure events have been generally small and are not expected to cause significant damage. The average overpressures recorded at the source of the RPTs during the Coyote tests have ranged from 0.2 pounds per square inch (psi) to 11 psi[5]. These events are typically limited to the area within the spill and are not expected to cause damage outside of the area engulfed by the LNG pool. However, a RPT may affect the rate of pool spreading and the rate of vaporization for a spill on water.

[5] The Lawrence Livermore National Laboratory conducted seven tests (the Coyote series) on vapor cloud dispersion, vapor cloud ignition, and RPTs at the Naval Weapons Center in China Lake, California in 1981.

Vapor Dispersion

In the event of a loss of containment, LNG would vaporize when released from any storage or process facilities. Depending on the size of the release, LNG may form a liquid pool and vaporize. Additional vaporization would result from exposure to ambient heat sources, such as water or soil. When released from a containment vessel or transfer system, LNG will generally produce 620 to 630 standard cubic feet of natural gas for each cubic foot of liquid.

If the loss of containment does not result in immediate ignition of the natural gas vapors, the vapor cloud would travel with the prevailing wind until it either encountered an ignition source or dispersed below its flammable limits. An LNG release would form a denser-than-air vapor cloud that would sink to the ground due to the cold temperature of the vapor. As the LNG vapor cloud disperses downwind and mixes with the warm surrounding air, the LNG vapor cloud may become buoyant. However, experimental observations and vapor dispersion modeling indicate the LNG vapor cloud would not typically be warm, or buoyant, enough to lift off from the ground before the LNG vapor cloud becomes too diluted to be flammable. As a result, estimating the dispersion of the vapor cloud is an important step in addressing potential hazards and will be discussed in Section 4.12.5.

Methane, the primary component of LNG, is classified as a simple asphyxiate and may pose extreme health hazards, including death, if inhaled in significant quantities within a limited time. Very cold methane vapors may also cause freeze burns. However, the locations of concentrations where cold temperatures and oxygen-deprivation effects could occur are greatly limited due to the continuous mixing with the warmer air surrounding the spill site. Exposure injuries from contact with releases of methane normally represent negligible risks to the public.

Vapor Cloud Ignition

Flammability of the methane vapor cloud would be dependent on the concentration of the vapor when mixed with the surrounding air. In general, higher concentrations within the vapor cloud would exist near the spill, and lower concentrations would exist near the edge of the cloud as it disperses downwind. Mixtures occurring between the lower flammability limit (LFL) and the upper flammability limit (UFL) could be ignited. Concentrations above the UFL or below the LFL would not ignite. The LFL and UFL for methane are approximately 5 percent by volume (%-vol) and 15%-vol in air, respectively. If the flammable portion of a vapor cloud encounters an ignition source, a flame would propagate through the flammable portions of the cloud. In most circumstances, the flame would be driven by the heat it generates, a process known as a deflagration. A methane vapor cloud deflagration in an uncongested and unconfined area travels at slower speeds and does not produce significant pressure waves. Confined and congested methane vapor clouds may produce higher flame speeds and overpressures, and are discussed later in Section 4.12.5 under “Overpressure Considerations.”

A deflagration may propagate back to the spill site if the vapor concentration along this path is sufficiently high to support the combustion process. When the flame reaches vapor concentrations above the UFL, the deflagration could transition to a fireball and result in a pool or jet fire back at the spill source. A fireball would occur near the source of the release and would be of a relatively short duration compared to an ensuing jet or pool fire.

The extent of the affected area and the severity of the impacts on objects either within an ignited cloud or in the vicinity of a pool fire would primarily be dependent on the quantity and duration of the initial release, the surrounding terrain, and the environmental conditions present during the dispersion of the cloud. Radiant heat and dispersion modeling for the on-shore facilities are discussed in Section 4.12.5. Impacts from LNG spills over water along the LNG carrier transit route are discussed in Section 4.12.7.

A vapor cloud fire can ignite combustible materials within the cloud and can also cause severe burns and death. Fires may also cause failures of nearby storage vessels, piping, and equipment. The failure of a pressurized vessel could cause fragments of material to fly through the air at high velocities, posing damage to surrounding structures and a hazard for operating staff, emergency personnel, or other individuals in proximity to the event. In addition, failure of a pressurized vessel when the liquid is at a temperature significantly above its normal boiling point could result in a boiling-liquid-expanding-vapor explosion (BLEVE). BLEVEs of flammable liquids can produce overpressures and a subsequent fireball when the superheated liquid rapidly changes from a liquid to a vapor upon the release from the vessel. Atmospheric storage tanks, such as those proposed for LNG storage in this project are unlikely to BLEVE due to the smaller difference between their design pressure and ambient pressure.

Overpressures

If the deflagration in a flammable vapor cloud accelerates to a sufficiently high rate of speed, pressure waves that can cause damage would be generated. As a deflagration accelerates to super-sonic speeds, the large shock waves produced, rather than the heat, would begin to drive the flame, resulting in a detonation. The flame speeds are primarily dependent on the reactivity of the fuel, the ignition strength and location, the degree of congestion and confinement of the area occupied by the vapor cloud, and the flame travel distance.

The potential for unconfined LNG vapor cloud detonations was investigated by the Coast Guard in the late 1970s at the Naval Weapons Center in China Lake, California. Using methane, the primary component of natural gas, several experiments were conducted to determine whether unconfined LNG vapor clouds would detonate. Unconfined methane vapor clouds ignited with low-energy ignition sources (13.5 joules), produced flame speeds ranging from 12 to 20 miles per hour (mph). These flame speeds are much lower than the flame speeds associated with a deflagration with damaging overpressures or a detonation.

To examine the potential for detonation of an unconfined natural gas cloud containing heavier hydrocarbons that are more reactive, such as ethane and propane, the Coast Guard conducted further tests on ambient-temperature fuel mixtures of methane-ethane and methane-propane. The tests indicated that the addition of heavier hydrocarbons influenced the tendency of an unconfined natural gas vapor cloud to detonate. Less processed natural gas with greater amounts of heavier hydrocarbons would be more sensitive to detonation.

Although it is possible to produce damaging overpressures and detonations of unconfined LNG vapor clouds, the LNG proposed for importation to the Downeast project would have lower ethane and propane concentrations than those that resulted in damaging overpressures and detonations. The substantial amount of initiating explosives needed to create the shock initiation during the limited range of vapor-air concentrations also renders the possibility of detonation of these vapors at an LNG plant as unrealistic. Ignition of a confined LNG vapor cloud could result in higher overpressures. In order to prevent such an occurrence, measures are taken to mitigate the vapor dispersion and ignition into confined areas, such as buildings. In general, the primary hazards to the public from an LNG spill that disperses to an unconfined area, either on land or water, would be from dispersion of the flammable vapors or from radiant heat generated by a pool fire. Discussion of these hazards and potential mitigation are in Section 4.12.5 for the on-shore facilities and in Section 4.12.7 for the LNG carrier transit route.

Past LNG Facility Incidents

With the exception of the October 20, 1944, failure at an LNG facility in Cleveland, Ohio, the operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 people.[6] The failure of the LNG storage tank was due to the use of materials inadequately suited for cryogenic temperatures. LNG migrating through streets and into underground sewers, due to the lack of adequate spill impoundments at the site, was also a contributing factor. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used and that spill impoundments are designed and constructed properly to contain a spill at the site.

[6] For a description of the incident and the findings of the investigation, see "U.S. Bureau of Mines, Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944," dated February 1946.

Another operational accident occurred in 1979 at the Cove Point LNG facility in Lusby, Maryland. A pump seal failure resulted in gas vapors entering an electrical conduit and settling in a confined space. When a worker switched off a circuit breaker, the gas ignited, causing heavy damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident resulted in changing the national fire codes to ensure that the situation would not occur again.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction facility, which killed 27 and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced to the high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40, and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981. To ensure that this potential hazard is addressed at the proposed Downeast LNG Project, all combustion and ventilation air intake equipment would be required to have hazard detection devices that would enable isolation and deactivation of any combustion equipment whose continued operation could add to or sustain an emergency.

4.12.3 Technical Review of the Preliminary Engineering Design

Operation of the proposed facility poses a potential hazard that could affect the public safety if strict design and operational measures to control potential accidents are not applied. The primary concerns are those events that could lead to an LNG spill of sufficient magnitude to create an off-site hazard as discussed in Section 4.12.2. However, it is important to recognize the stringent requirements in place for the design, construction, operation, and maintenance of the facility, as well, as the extensive safety systems proposed to detect and control potential hazards.

As part of a project's preliminary safety review, Downeast's design development team conducted a hazard and operability review (HAZOP) analysis of the Front-End Engineering Design (FEED) to identify the major hazards that may be encountered during the operation of facilities. The HAZOP study addresses hazards of the process, engineering and administrative controls, and provides a qualitative evaluation of a range of possible safety, health, and environmental effects which may result from the design or operation of the facility. Recommendations to prevent or minimize these hazards are generated from the results of the HAZOP review. These studies help establish the required safety control levels and identify whether additional process and safety instrumentation, mitigation, and/or administrative controls would be needed. In addition, a HAZOP review of the completed design would be performed by Downeast's design development team during the detailed design phase.

Once the design has been subjected to a HAZOP review, the design development team tracks changes in the facility design, operations, documentation, and personnel. These changes would be evaluated to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled. Resolution of the recommendations generated by the HAZOP review are also monitored.

Based on these analyses, various layers of protection or safeguards would be included in the facility design to reduce the risk of a potentially hazardous scenario from developing into an event that could impact the off-site public. These layers of protection are independent of one another so that any one would perform its function regardless of the action or failure of any other protection layer or initiating event. These layers of protection typically include:

- A facility design that prevents hazardous events through the use of suitable materials of construction; operating and design limits for process piping, process vessels, and storage tanks; adequate design for wind, flood, seismic, and other outside hazards;

- Control systems, including monitoring systems and process alarms, remotely-operated control and isolation valves, and operating procedures to ensure the facility stays within the established operating and design limits;

- Safety-instrumented prevention systems, such as safety control valves and emergency shutdown systems, to prevent a release if operating and design limits are exceeded;

- Physical protection systems, such as appropriate electrical area classification, proper equipment and building spacing, pressure relief valves, spill containment, and structural fire protection, to prevent escalation to a more severe event;

- Site security measures for controlling access to the facility, including security inspections and patrols; response procedures to any breach of security; and liaison with local law enforcement officials; and

- On-site and off-site emergency response, including hazard detection and control equipment, firewater systems, and coordination with local first responders to mitigate the consequences of a release and prevent it from escalating to an event that could impact the public.

The use of these protection layers would mitigate the potential for an initiating event to develop into an incident that could damage the facility, injure operating staff, or impact the safety of the off-site public. In addition, proper siting of the facility with regard to potential off-site consequences is required to ensure that the public is protected. These siting requirements are discussed in Section 4.12.4.

As part of the application, Downeast provided a FEED for the project. The FEED and specifications submitted for the proposed facilities to date are preliminary, but would serve as the basis for any detailed design to follow. During the FERC review process, we analyzed the information filed by Downeast to determine the extent that layers of protection or safeguards to enhance the safety, operability, and reliability of the facility are included in the FEED.

As a result of the technical review of the information provided by Downeast in the submittal documents, we identified a number of concerns relating to the reliability, operability, and safety of the proposed design. In response to staff's questions, Downeast provided written responses prior to the technical conference held on April 25, 2007. However, some of these responses indicated that corrections or modifications would be made to the design in order to address issues raised in the information request. As a result, **we recommend that**:

- **<u>Prior to construction of the final design</u>, Downeast should provide information/revisions related to those responses in their April 10, 2007 filing that state that corrections or modifications would be made to the design. The final design should specifically address response numbers 2, 8, 10, 13, 15, 23, 24, 25, 26, 27, 30, 31, 33, 34, 38, 51, 54, 56, 59, 61, and 70 using management of change procedures.**

The objectives of our FEED review focused on the engineering design and safety concepts of the various protection layers, as well as the projected operational reliability of the proposed facilities. The design would use materials of construction suited to the pressure and temperature conditions of the process design. Piping would be designed in accordance with American Society of Mechanical Engineers (ASME) B31.3. Pressure vessels would be designed in accordance with ASME Section VIII and the storage tanks would be designed in accordance with American Petroleum Institute (API) Standard 620 per 49 CFR 193 and the National Fire Protection Association's Standard 59A (NFPA 59A). Valves and other equipment would be designed to recommended and generally accepted good engineering practices. The facility would also be designed to withstand the effects of hurricane force winds with a design wind velocity of 150 mph for the process equipment containing LNG, per the requirements of ASCE 7-05, Minimum Design Loads for Buildings and Other Structures. All onshore structures at the terminal would be at a height of 50 feet or greater above sea level (North American Vertical Datum of 1988) to minimize the risk of flooding. As discussed in Section 4.1.4 of the 2009 draft EIS, we also examined the seismic and structural design of the facility and provided recommendations to deal with the issues identified.

Process control valves and instrumentation would be installed to safely operate and monitor the facility. Alarms would have visual and audible notification in the control room to warn operators that process conditions may be approaching design limits. Operators would have the capability to take action from the control room to mitigate an upset.

Downeast would develop facility operations procedures after completion of the final design; this timing is fully consistent with accepted industry practice. We are recommending that Downeast provide more information on the operating and maintenance procedures as they are developed, including safety procedures, hot work procedures and permits, abnormal operating conditions procedures, training of personnel. In addition, we are recommending measures, such as equipment/pipe labeling and valve car-seals/locks, to address human factor considerations and improve facility safety. An alarm management program would also be in place to ensure effectiveness of the alarms.

Safety valves and instrumentation would be installed to monitor, alarm, shutdown, and isolate equipment and piping during process upsets or emergency conditions. Safety instrumented systems would comply with International Society for Automation (ISA) Standard 84.01 and other recommended and generally accepted good engineering practices. We are also recommending changes to the design, installation, and commissioning of instrumentation and emergency shutdown equipment to ensure appropriate cause and effect alarm or shutdown logic and enhanced representation of the emergency shutdown valves in the facility control system.

Safety relief valves, vent stacks, and flares would be installed to protect the process equipment and piping. The safety relief valves would be designed to handle process upsets and thermal expansion within piping, per NFPA 59A and ASME Section VIII, and would be designed based on API 521. The safety relief valves would also meet API 527 and other recommended and generally accepted good engineering practices. In addition, we are making recommendations for changes to the design and installation of pressure and vacuum relief devices to ensure appropriate discharge and separate handling of LNG and natural gas.

In order to minimize the risk of an intentional event, Downeast would provide security fencing, lighting, camera systems, and intrusion detection to deter, monitor, and detect intruders into the facility. In addition, as discussed in Section 4.12.5, Downeast would be required to develop a Facility Security Plan in accordance with the Coast Guard's regulations found in 33 CFR 105, Subpart D. We are also recommending that Downeast provide site access control during construction and security and incident reporting during operation.

In the event of a release, LNG and process facilities would be provided with a drainage system or spill system designed to direct a spill away from equipment in order to minimize flammable vapors from dispersing to confined, occupied, or public areas and to minimize heat from impacting adjacent equipment and public areas if ignition occurs. We also made recommendations on the spacing and design of impoundments to minimize damage to equipment and buildings. Impoundment systems are further discussed in 4.12.5.

Downeast performed a preliminary fire protection evaluation to ensure that adequate hazard detection, hazard control, and firewater coverage would be installed to detect and address any upset conditions. Structural fire protection, proposed to prevent failure of structural supports of equipment and piperacks, would comply with NFPA 59A and other recommended and generally accepted good engineering practices. Hazard detection systems would also be installed to detect, alarm, and alert personnel in the area and control room to initiate an emergency shutdown and/or initiate appropriate procedures, and would meet NFPA 72, ISA 12.13, and other recommended and generally accepted good engineering practices. Hazard control devices would be installed to extinguish or control incipient fires and releases, and would meet NFPA 59A and NFPA 10, 11, 12, and 17 requirements, and other recommended and generally accepted good engineering practices. Automatic firewater systems and monitors would be provided for use during an emergency to cool the surface of storage vessels, piping, and equipment exposed to heat from a fire, and would meet NFPA 59A, 20, 22, 24, and 25 requirements. We also made recommendations for the provision of a clean agent system in the power distribution building and for Downeast to provide a finalized fire protection evaluation. In addition, we are making recommendations for Downeast to provide more information on the design, installation, and commissioning of hazard detection, hazard control, and firewater systems as this information would be developed during the final design phase.

Downeast would also have emergency procedures in accordance with 49 CFR 193 and 33 CFR 127. The emergency procedures would provide for protection of personnel and the public as well as the prevention of property damage that may occur as a result of incidents at the facility. Downeast would also be required to develop an emergency response plan (ERP) in accordance with the Energy Policy Act of 2005 (EPAct 2005), as discussed further in Section 4.12.8.

If authorization is granted by the Commission, the next phase of the project would include development of the final design, including final selection of equipment manufacturers, process conditions, and resolution of some safety-related issues. To ensure the final design would be consistent with the safety and operability characteristics identified in the FEED, information regarding the development of the final design, as detailed below, would need to be filed with the Secretary of the Commission (Secretary) for review and written approval by the Director of the Office of Energy Projects (OEP) before equipment construction at the site would be authorized.

In addition to the final design review, we would conduct inspections during construction and would review additional materials, including quality assurance and quality control plans, non-conformance reports, and cooldown and commissioning plans to ensure that the installed design would be consistent with the safety and operability characteristics of the FEED. We would also conduct inspections during operation to ensure that the facility would be operated and maintained in accordance with the filed design throughout the life of the facility.

To ensure that the concerns we identified relating to the reliability, operability, and safety of the proposed design are addressed by Downeast, and would be subject to the Commission's construction and operational inspection program, **we recommend that the following measures be applied to the Downeast LNG terminal. Information pertaining to these specific recommendations should be filed with the Secretary for review and written approval by the Director of OEP either: <u>prior to initial site preparation</u>; <u>prior to construction of final design</u>; <u>prior to commissioning</u>; <u>prior to introduction of natural gas or process fluids</u>; or <u>prior to commencement of service</u>, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, should be submitted as critical energy infrastructure information (CEII) pursuant to 18 CFR 388.112. See CEII Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. ¶31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements would be subject to public disclosure. All information should be filed a minimum of 30 days before approval to proceed is requested.**

- **<u>Prior to initial site preparation</u>, Downeast should provide an Implementation Plan which identifies when Downeast would provide:**
  - **a. quality assurance and quality control procedures for construction activities;**
  - **b. a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems;**
  - **c. an equipment list of the final design which should include; tag numbers, manufacturer, design pressure and Maximum Allowable Working Pressure (MAWP), design temperature and Minimum Design Metal Temperature (MDMT), equipment dimensions, design and normal liquid storage capacity; rated and normal flow capacity, rated and normal heating capacity, heat transfer area, motor horsepower and voltage, as applicable;**
  - **d. spill containment system drawings of the final design with dimensions and slopes of curbing, trenches, and impoundments;**
  - **e. electrical area classification drawings of the final design;**

f. drawings and details of all process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system for the final design;

g. the sizing basis and capacity for the final design of: pressure and vacuum relief valves for major process equipment, vessels, and storage tanks; and vent stacks;

h. procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3 required by 49 CFR 193;

i. results of the LNG storage tank hydrostatic test and foundation settlement results;

j. a commissioning plan; and

k. a cooldown plan.

- **<u>Prior to initial site preparation</u>, Downeast should file an overall project schedule, which includes the proposed stages of the commissioning plan.**

- **<u>Prior to initial site preparation</u>, Downeast should provide procedures for controlling access during construction.**

- **<u>Prior to initial site preparation</u>, Downeast should file complete plan drawings and a list of the hazard detection equipment. Plan drawings should clearly show the location of all detection equipment. The list should include the instrument tag number, type and location, alarm locations, and shutdown functions of the proposed hazard detection equipment.**

- **<u>Prior to initial site preparation</u>, Downeast should provide a technical review of its proposed facility design that:**

  a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids and flammable gases); and

  b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.

- **<u>Prior to initial site preparation</u>, Downeast should file plan drawings and a list of the fixed and wheeled dry-chemical, fire extinguishing, and other hazard control equipment. Plan drawings should clearly show**

the planned location of all fixed and wheeled extinguishers. The list should include the equipment tag number, type, size, equipment covered, and automatic and manual remote signals initiating discharge of the units.

- **<u>Prior to initial site preparation</u>, Downeast should file facility plans and drawings showing the proposed location of the firewater and high-expansion foam system. Plan drawings should clearly show the planned location of firewater and high expansion foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, high-expansion foam generator, and sprinkler. The drawings should also include piping and instrumentation diagrams of the firewater and high expansion foam systems.**

- **<u>Prior to initial site preparation</u>, Downeast should file a complete specification of the proposed LNG tank design and installation.**

- **<u>Prior to initial site preparation</u>, Downeast should file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances.**

- **<u>Prior to initial site preparation</u>, Downeast should file complete plan drawings of the security fencing and of facility access and egress, including the details of the fence and control access and egress from the pipe trestle and dock.**

- **The <u>final design</u> should include up-to-date Process Flow Diagrams (PFDs) with heat and material balances and Piping and Instrumentation Diagrams (P&IDs). The P&IDs should include the following information:**

  a. equipment tag number, name, size, duty, capacity, and design conditions;

  b. equipment insulation type and thickness;

  c. storage tank pipe penetration size or nozzle schedule;

  d. piping with line number, piping class specification, size, and insulation type and thickness;

  e. piping specification breaks and insulation limits;

  f. all control and manual valves numbered;

  g. relief valves with set points;

  h. drawing revision number and date; and

i. **change log that lists and explains the changes made from the approved design.**

- **The <u>final design</u> should include a list of all car-sealed and locked valves consistent with the P&IDs.**

- **The <u>final design</u> of the fixed and wheeled dry-chemical, fire extinguishing hazard control equipment should identify manufacturer and model.**

- **The <u>final design</u> should include an updated fire protection evaluation carried out in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2. The fire protection evaluation should address measures on the prevention of caustic water from entering the firewater tank.**

- **The <u>final design</u> should specify that the design pressure of sendout equipment containing LNG in low pressure service should be not less than the design pressure of the piping system.**

- **The <u>final design</u> should specify that LNG relief valves and LNG drains should not discharge into the vapor system.**

- **The <u>final design</u> should specify that LNG from relief valves and drains is to be returned to storage.**

- **The <u>final design</u> should include provision for vehicle access roads to and from the north and south of the LNG pump and vaporizer area.**

- **The <u>final design</u> of the vapor return system should include provisions for the addition of LNG transfer pumps to the Jetty Drum D-103. The vapor inlet piping to the drum should be designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping.**

- **The <u>final design</u> should include provisions for the future installation of LNG pumps for the boil-off gas (BOG) drum.**

- **The <u>final design</u> should specify that the vapor inlet piping to the BOG drum should be designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping.**

- **The final design should specify that the Low Point Drain Drum is to be equipped to remove residual liquids without personnel accessing the spill containment sump.**

- **The final design of the Low Point Drain Drum should include a pressure relief system, to protect the vessel in the event of isolation.**

- **The final design of the boil-off condenser system should include a relief valve between the vapor inlet check valve and the fail closed LNG outlet control valve.**

- **The final design should include provisions to recycle the boil-off compressor discharge to upstream of the BOG drum desuperheater.**

- **The final design should include car-seal or locked closed bypass valves around the intank pump ESD2 discharge valves as opposed to minimum stop set points for ESD2 valves, for cooldown of the 20-inch diameter header and piping.**

- **The final design should include a shutoff valve at the suction and discharge of each high pressure pump.**

- **The final design should specify that the minimum flow recycle line from the high pressure LNG pumps to downstream of the isolation valve to the LNG storage tanks should be the same pressure and temperature rating as the piping at the discharge of the high pressure LNG pumps.**

- **The final design should include a relief valve or operated vent valve sized for thermal relief at the discharge of each vaporizer, upstream of the isolation valves. This relief valve is in addition to the relief valve specified in NFPA 59A and should be set at a lower pressure.**

- **The final design should include LNG tank fill flow measurement with high flow alarm.**

- **The final design should include a discretionary vent valve for each LNG tank, operable through the Distributed Control System (DCS).**

- **The final design should include BOG flow and temperature measurement for each tank.**

- **The final design should specify that all emergency shutdown (ESD) valves are to be equipped with open and closed position switches connected to the DCS/Safety Instrumented System (SIS).**

- **The final design should include a clean agent system in the power distribution building.**

- **The final design should include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire.**

- **The final design should specify that all drains from high pressure LNG systems are to be equipped with double isolation and bleed valves.**

- **The final design should specify that for LNG and natural gas service, branch piping and piping nipples less than 50 millimeters (2 inches), are to be no less than schedule 160 up to the first isolation valve.**

- **The final design should specify that piping and equipment that may be cooled with liquid nitrogen is to be designed for liquid nitrogen temperatures, with regard to allowable movement and stresses.**

- **The final design should include details of the shut-down logic, including cause and effect matrices for alarms and shutdowns.**

- **The final design should include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable.**

- **The final design should include details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A.**

- **The final design should include details of the air gaps to be installed downstream of all process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap should vent to a safe location and be equipped with a leak detection device that: should continuously monitor for the presence of a flammable fluid; should alarm the hazardous condition; and should shutdown the appropriate systems.**

- **The <u>final design</u> should include a HAZOP review of the completed design. A copy of the review, a list of the recommendations, and actions taken on the recommendations should be filed.**

- **The <u>final design</u> should include provisions to install high pressure boil-off compression or BOG liquefaction in the event that sendout operation is curtailed, or ceased for a period in excess of thirty days. Details should include plans and drawings of the BOG recovery system and specifications of the equipment and compressors to be installed.**

- **The <u>final design</u> should include provisions to remove LNG from the inlet of the vaporizer due to shutdown sequence.**

- **The <u>final design</u> should include a plan for clean-out, dry-out, purging, and tightness testing. This plan should address the requirements of the American Gas Association's Purging Principles and Practice required by 49 CFR 193.**

- **The <u>final design</u> should include a vent stack dispersion analysis to determine the proper placement of hazard detection devices that ensures venting is done in a safe manner.**

- **The <u>final design</u> should specify that the vent stack be equipped with a discharge piece designed for ignited discharge conditions.**

- **<u>Prior to commissioning</u>, Downeast should file a copy of the Mechanical Completion Certificate and any documentation (i.e., punch list items) that certifies that the facility is installed and mechanically tested according to the final design and specifications.**

- **<u>Prior to commissioning</u>, Downeast should tag all instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**

- **<u>Prior to commissioning</u>, Downeast should maintain a name plate database containing photographic documentation of all major equipment.**

- **<u>Prior to commissioning</u>, Downeast should file the design details and procedures to record and to prevent the tank fill rate from exceeding the maximum fill rate specified by the tank designer.**

- **<u>Prior to commissioning</u>, Downeast should file a tabulated list and complete drawings of the proposed hand-held fire extinguishers. The**

list should include the equipment number, type, size, number, and location. Plan drawings should include the type, size, and number of all hand-held fire extinguishers.

- **<u>Prior to commissioning</u>, Downeast should file Operation and Maintenance procedures and manuals, , including safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, and management of change procedures and forms.**

- **<u>Prior to commissioning</u>, Downeast should maintain a detailed training log to demonstrate that operating staff has completed the required training.**

- **<u>Prior to commissioning</u>, Downeast should file a plan for functional and operational tests of the final design.**

- **<u>Prior to introduction of natural gas or process fluids</u>, Downeast should file a copy of the Ready for Cooldown Certificate and any documentation (i.e., punch list items) that certifies the facility is operational and functionally tested according to the final design and specifications.**

- **<u>Prior to introduction of natural gas or process fluids</u>, Downeast should file a cooldown plan. During cooldown, Downeast should report progress on the development of cooldown in daily reports.**

- **<u>Prior to introduction of natural gas or process fluids</u>, Downeast should complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS and SIS that demonstrates full functionality and operability of the system.**

- **<u>Prior to introduction of natural gas or process fluids</u>, Downeast should complete instrumentation functional tests, hazard detection equipment functional tests, and ESD tests.**

- **<u>Prior to introduction of natural gas or process fluids</u>, hazard control and security components and systems should be installed and functional.**

- **<u>Prior to introduction of natural gas or process fluids,</u> Downeast should complete a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant should be shown on facility plot plan(s).**

- **<u>Prior to commissioning</u>, Downeast should label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A.**

- **<u>Prior to commencement of service</u>, Downeast should develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Downeast staff.**

- **<u>Prior to commencement of service</u>, Downeast should notify FERC staff of any proposed revisions to the security plan and physical security of the facility.**

- **<u>Prior to commencement of service</u>, Downeast should file progress on construction of the LNG terminal in <u>monthly</u> reports. Details should include a summary of activities, problems encountered, contractor non-conformance/deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude should be reported to the FERC <u>within 24 hours</u>.**

In addition, the following measures should apply throughout the life of the facility:

- **The facility should be subject to regular FERC staff technical reviews and site inspections on at least an <u>annual</u> basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Downeast should respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed piping and instrumentation diagrams reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted annual report, should be submitted.**

- **<u>Semi-annual</u> operational reports should be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals/departures, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), and plant modifications including future plans and progress thereof. Abnormalities should include, but not be limited to: unloading/loading shipping problems, potential hazardous conditions caused by off-site transportation, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks,**

storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, nonscheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, vapor or liquid releases, fires involving natural gas and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boiloff rates. Adverse weather conditions and the effect on the facility should also be reported. Reports should be submitted <u>within 45 days after each period ending June 30 and December 31</u>. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" should also be included in the semiannual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.

- **In the event the temperature of any region of any secondary containment, including imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission should be notified <u>within 24 hours</u> and procedures for corrective action should be specified.**

- **Significant non-scheduled events, including safety-related incidents (e.g., LNG, refrigerant or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) should be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification should be made <u>immediately</u>, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification should be made to FERC staff <u>within 24 hours</u>. This notification practice should be incorporated into the LNG facility's emergency plan. Examples of reportable LNG or refrigerant related incidents include:**

  a. fire;

  b. explosion;

  c. estimated property damage of $50,000 or more;

  d. death or personal injury necessitating in-patient hospitalization;

  e. release of LNG or refrigerants for five minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;

g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;

h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas, refrigerants, or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;

i. a leak in an LNG facility that contains or processes gas, refrigerants, or LNG that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operation of a pipeline or an LNG facility that contains or processes gas, refrigerants, or LNG;

l. safety-related incidents to LNG or refrigerant transportation occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow-up report or follow-up in the upcoming semi-annual operational report. All company follow-up reports should include investigations results and recommendations to minimize a reoccurrence of the incident.

4.12.4 Siting Requirements

The Commission's regulations under 18 CFR 380.12(o)(14) require Downeast to identify how the proposed design complies with the siting requirements of DOT's regulations in 49 CFR 193, Subpart B. The Part 193 requirements state that an operator or government agency must exercise control over the activities that can occur within an "exclusion zone," defined as the area around an LNG facility that could be exposed to specified levels of thermal radiation or flammable vapor in the event of a release. Approved mathematical models must be used to calculate the dimensions of these exclusion zones. The 2001 edition of NFPA 59A, an industry consensus safety standard for the siting, design, construction, operation, maintenance, and security of LNG facilities, is incorporated into Part 193 by reference, with regulatory preemption in the event of conflict. The following sections of Part 193 specifically address the siting requirements applicable to each LNG container and LNG transfer system:

- Part 193.2001, *Scope of part*, excludes any matter other than siting provisions pertaining to marine cargo transfer systems between the marine vessel and the last manifold or valve immediately before a storage tank.

- Part 193.2051, *Scope*, states that each LNG facility designed, replaced, relocated or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with Subpart B and NFPA 59A (2001). In the event of a conflict with NFPA 59A (2001), the regulatory requirements in Part 193 prevail.

- Part 193.2057, *Thermal radiation protection*, requires that each LNG container and LNG transfer system have thermal exclusion zones in accordance with Section 2.2.3.2 of NFPA 59A (2001).

- Part 193.2059, *Flammable vapor-gas dispersion protection*, requires that each LNG container and LNG transfer system have a dispersion exclusion zone in accordance with Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001).

For the LNG facilities proposed for this project, these Part 193 siting requirements would be applicable to the following equipment:

- Two 42,267,530 gallon (net) full containment LNG storage tanks and associated piping and appurtenances - Parts 193.2057 and 2059 require the establishment of thermal and flammable vapor exclusion zones for LNG tanks. NFPA 59A (2001), section 2.2.3.2 specifies four thermal exclusion zones based on the design spill and the impounding area. NFPA 59A (2001), sections 2.2.3.3 and 2.2.3.4 specify a flammable vapor exclusion zone for the design spill which is determined with section 2.2.3.5.

- A pier comprised of a single LNG carrier berth and a marine cargo transfer system, consisting of three 16-inch-diameter liquid transfer arms and one 16-inch-diameter vapor return arm, a single 36-inch-diameter LNG transfer pipe, and other associated process vessels, piping and appurtenances. Parts 193.2001, 2057, and 2059 require thermal and flammable vapor exclusion zones for the marine cargo transfer system. NFPA 59A (2001) does not address LNG transfer systems.

- Four 4,600 gallon per minute (gpm) low pressure in-tank pumps (two per tank; one operating and one spare) and associated piping and appurtenances; and four 1,400 gpm high pressure (HP) sendout pumps (three operating and one spare) and associated process vessels, piping, and appurtenances - Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) section 2.2.3.2 specifies the thermal exclusion zone and sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spills for containers and process areas.

- Four submerged combustion vaporizers (SCVs) and associated process vessels, piping, and appurtenances- Parts 193.2057 and 2059 require thermal and flammable vapor exclusion zones. NFPA 59A (2001) section 2.2.3.2 specifies the thermal exclusion zone and sections 2.2.3.3 and 2.2.3.4 specify the flammable vapor exclusion zone based on the design spill in a process area.

Previous FERC environmental assessments/impact statements for past projects have identified inconsistencies and areas of potential conflict between the requirements in Part 193 and NFPA 59A (2001). Sections 193.2057 and 193.2059 require exclusion zones for each LNG container and LNG transfer system, and an LNG transfer system is defined in section 193.2007 to include cargo transfer system and transfer piping (whether permanent or temporary). However, NFPA 59A (2001) requires exclusion zones only for “transfer areas,” which is defined as the part of the plant where the facility introduces or removes the liquids, such as truck loading or ship-unloading areas. The NFPA 59A (2001) definition does not include permanent plant piping, such as cargo transfer lines. Section 2.2.3.1 of NFPA 59A (2001) also states that transfer areas at the water edge of marine terminals are not subject to the siting requirements in that standard.

The DOT addressed some of these issues in a March 2010 letter of interpretation.[7] In that letter, DOT stated that: (1) the requirements in the NFPA 59A (2001) for transfer areas for LNG apply to the marine cargo transfer system at a proposed waterfront LNG facility, except where preempted by the regulations in Part 193; (2) the regulations in Part 193 for LNG transfer systems conflict with the NFPA 59A (2001) on whether an exclusion zone analysis is required for transfer piping or permanent plant piping; and (3) the regulations in Part 193 prevailed as a result of that conflict. The DOT determined that an exclusion zone analysis of the marine cargo transfer system is required.

In FERC environmental assessments/impact statements for past projects, we also noted that when the DOT incorporated NFPA 59A into its regulations, it removed the regulation that required impounding systems around transfer piping. As a result of that change, it is unclear whether Part 193 or the adopted sections of NFPA 59A (2001) require impoundments for LNG transfer systems. We note that Part 193 requires exclusion zones for LNG transfer systems, and that those zones are calculated based on impoundment systems. We also note that the omission of containment for transfer piping is not a sound engineering practice. For these reasons, we generally recommend containment for all LNG transfer piping within a plant's property lines.

Federal regulations issued by the Occupational Safety and Health Administration (OSHA) under 29 CFR § 1910.119 (Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents (PSM)), and the U.S. EPA under 40 CFR 68 (Risk Management Plans) cover hazardous substances, such as methane, propane and ethylene at many facilities in the United States. However, OSHA and EPA regulations are not applicable to facilities regulated under 49 CFR 193. On October 30, 1992, shortly after the promulgation of the OSHA PSM regulations, OSHA issued a letter of interpretation that precluded the enforcement of PSM regulations over gas transmission and distribution facilities. In a subsequent letter on December 9, 1998, OSHA further clarified that this letter of interpretation applies to LNG distribution and transmission facilities.

In addition, EPA's preamble to its final rule in Federal Register, Volume 63, Number 3, 639-645, clarified that exemption from the requirements in 40 CFR 68 for regulated substances in transportation, including storage incident to transportation, is not limited to pipelines. The preamble further clarified that the transportation exemption applies to LNG facilities subject to oversight or regulation under 49 CFR 193, including facilities used to liquefy natural gas or used to transfer, store, or vaporize LNG in conjunction with pipeline transportation.

[7] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) Interpretation "Re: Application of the Siting Requirements in Subpart B of 49 CFR Part 193 to the Mount Hope Bay Liquefied Natural Gas Transfer System" (March 25, 2010).

4.12.5 Siting Analysis

Suitable sizing of impoundment systems and selection of design spills on which to base hazard analyses are critical for establishing an appropriate siting analysis. Although impoundment capacity and design spill scenarios for storage tank impoundments are well described by Part 193, a clear definition for other impoundments is not provided either directly by the regulations or by the adopted sections of NFPA 59A (2001). Under NFPA 59A (2001) Section 2.2.2.2, the capacity of impounding areas for vaporization, process, or LNG transfer areas must equal the greatest volume that can be discharged from any single accidental leakage source during a 10-minute period or during a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to the DOT. However, no definition of single accidental leakage source is provided in the regulations.

We recommend that impoundments be sized based on the greatest flow capacity from a single transfer pipe for 10 minutes, recognizing that different spill scenarios may be used for the single accidental leakage sources for calculation of Part 193 exclusion zones. A similar approach is used with impoundments for process vessels. We expect these impoundments be able to contain the contents of the largest process vessel served, while recognizing that smaller design spills may be appropriate for Part 193 exclusion zone calculations.

Impoundment Sizing

Part 193.2181 references NFPA 59A (2001) for siting, which specifies each impounding system serving an LNG storage tank must have a minimum volumetric liquid capacity of 110 percent of the LNG tank's maximum design liquid capacity for an impoundment serving a single tank. We also consider it prudent design practice to provide a barrier to prevent liquid from flowing to an unintended area (i.e., outside the plant property) in the event that the full containment storage tank primary and secondary containers have a common cause failure. The purpose of the barrier is to prevent liquid from flowing off the plant property, and does not define containment or an impounding area for thermal radiation or flammable vapor exclusion zone calculations or other code requirements already met by sumps and impoundments throughout the site.

Downeast proposes two full-containment LNG storage tanks where the outer tank wall would serve as the impoundment system. As shown in table 4.12.5-1, the outer tank would have a volumetric capacity of 52,116,919 gallons, which exceeds the 110 percent requirement by 4,737,902 gallons. The outer tank would contain 116 percent capacity of the inner tank, meeting the Part 193 requirements. Downeast also proposes to install an earthen rock barrier around the LNG tanks and associated process area to limit liquid from flowing off the plant property in the case of a common cause failure of the full containment storage tank primary and secondary containers. The structure would be 21 feet in height for the barrier and would enclose an area of approximately 10 acres. The structure's volumetric capacity would contain a single LNG tank's maximum liquid capacity and would meet our recommendation that a barrier be provided to prevent liquid from flowing off plant property.

Downeast proposes three insulated concrete impoundment basins to contain possible LNG spills from piping and process areas: the Process Area Impoundment Basin; the Vaporizer Area Impoundment Basin; and the Transfer Area Impoundment Basin.

The Process Area Impoundment Basin would serve the curbed area around the LNG storage tanks and the in-tank pumps. In this area, the greatest flow capacity from a single transfer pipe would be from the in-tank pump withdrawal header. Although each tank has space for three pumps, Downeast proposes to install only two pumps in this application, leaving the third pump column for future expansion. After the 2009 draft EIS was issued, Downeast revised the Process Area Impoundment Basin to have dimensions of 24-feet-wide by 24-feet-long by 22-feet-deep.[8] The sump would have a volume of 94,793 gallons to contain a header spill with the two in-tank pumps running [(4,600 gpm rated flow) x (2 in-tank pumps) x (10 minutes) = 92,000 gallons]. The Process Area Impoundment Basin would also be able to contain the 8,300 gallon HP Pump Drum, which is largest process vessel serving the impoundment. However, using the pump rated flow neglects the potential maximum pump run-out flow rate of the in-tank pumps, which would produce a volume of 115,000 gallons [(5,750 gpm maximum flow) x (2 in-tank pumps) x (10 minutes)]. As shown in table 4.12.5-1, the impoundment would need to be increased by more than 20,200 gallons to capture the full sizing spill, which could have an impact on the facility siting analysis. As a result, **we recommend that:**

- **<u>Prior to the end of the Supplemental draft EIS comment period</u>, Downeast should file a revised Process Area Impoundment Basin design which has the capacity to accommodate the maximum pump run-out flow.**

Any future installation of a third in-tank pump would require another application to FERC under Section 3 of the Natural Gas Act and a new siting analysis. In addition, Downeast would need to provide additional impoundment space, either by increasing the Process Area Impoundment or by providing another impoundment.

The Vaporizer Area Impoundment Basin would be located to the west of the vaporizers and would serve all four of the SCVs. After the 2009 draft EIS was issued, Downeast

[8] The original design of the Process Area Impoundment Basin listed in the application was 30-feet-wide by 30-feet-long by 22-feet-deep, equating to an available capacity of 148,114 gallons. This size appeared to be based on potential flow from a third in-tank pump, even though the application only proposed two pumps.

revised the Vaporizer Area Impoundment Basin to have dimensions of 20-feet-wide by 20-feet-long by 22-feet-deep.[9] The sump would have a volume of 65,828 gallons. There would be no process vessels which would drain to the Vaporizer Area Impoundment Basin. As stated above, we recommend the use of the greatest flow capacity from a single transfer pipe for 10 minutes for sizing impoundments. In this case, this would be the failure of the 16-inch-diameter vaporizer inlet line using the pump run-out flow rate and all four proposed pumps (including the backup pump that would be installed). This sizing spill yields a volume of 75,040 gallons [(1,876 gpm maximum pump run-out flow rate) x (4 high-pressure pumps) x (10 minutes)]. As shown in table 4.12.5-1, the impoundment would need to be increased by more than 9,200 gallons to capture the full sizing spill, which could have an impact on the facility siting analysis. As a result, **we recommend that:**

- **<u>Prior to the end of the Supplemental draft EIS comment period</u>, Downeast should file a revised Vaporizer Area Impoundment Basin design which has the capacity to accommodate the maximum pump run-out flow.**

The Transfer Area Impoundment Basin would serve the loading and recirculation lines and would have dimensions of 60-feet-wide by 60-feet-long by 24-feet-deep (this would also be equipped with internal weirs 45-feet-wide by 45-feet-long by 24-feet-deep). These dimensions yield an available capacity of 646,317 gallons. Downeast sized this impoundment basin for a full rupture of the unloading line during unloading operations. The 36-inch-diameter unloading line would have a flow rate of 61,745 gpm, equating to a sizing spill of 617,450 gallons over a 10-minute period. As shown in table 4.12.5-1, the Transfer Area Impoundment Basin would contain the above-mentioned spill. The Transfer Area Impoundment Basin would also be able to contain the 5,300 gallon Jetty Drum, which is largest process vessel serving the impoundment.

Table 4.12.5-1: Impoundment Area Sizing

Source	Spill Size (gallons)	Impoundment System	Impoundment Size (gallons)
LNG Storage Tank	45,117,046	Outer Tank Concrete Wall	52,116,919
In-tank pump withdrawal header	115,000	Process Area Impoundment Basin (S-606)	94,793
HP pump discharge line	75,040	Vaporization Area Impoundment Basin (S-607)	65,828
36-inch Unloading Line	617,450	Transfer Area Impoundment Basin (s-608)	646,317

[9] The original Vaporizer Area Impoundment Basin listed in the application was 30-feet-wide by 30 feet-long by 22-feet-deep, equating to an available capacity of 148,114 gallons.

Design Spills

Design spills are used in the determination of vapor dispersion and thermal radiation exclusion zones required by Part 193. Prior to the incorporation of NFPA 59A in 2000, the design spill in Part 193 assumed the full rupture of “a single transfer pipe which has the greatest overall flow capacity” for not less than 10 minutes (old Part 193.2059(d)). With the adoption of NFPA 59A, the basis for the design spill for impounding areas serving only vaporization, process, or LNG transfer areas became the flow from any single accidental leakage source.

As neither Part 193 nor NFPA 59A (2001) defines “single accidental leakage source”, FERC staff sent a letter to the DOT on April 19, 2005, requesting concurrence on proposed procedures for determining a single accidental leakage source. As described in that letter, FERC staff based the determination of the single accidental leakage source on an evaluation of all small diameter attachments to the transfer piping for instrumentation, pressure relief, recirculation, etc., and any flanges that may be used at valves or other equipment, in order to determine the largest spill rate. The DOT affirmed this approach in a May 6, 2005 response.

However, this approach does not provide any quantitative justification for the selection of the design spill to be used in Part 193 hazard & exclusion zone calculations. A wide variety of single accidental leakage sources, ranging from packing and flange leaks to full guillotine ruptures of ship unloading lines, have been proposed in applications before the FERC. To achieve a consistent approach, we began using equipment failure rates to establish a more quantitative threshold for single accidental leakage source under Part 193. Table 4.12.5-2 provides types of failures and associated failure rates (Mniszewski, 1984; GRI, 1981; Welker, 1979; Pelto, 1984; Pelto, 1982; Mannan, 2005; RIVM, 1999; RIVM, 1992; RIVM, 1997; HSE, 2011; RIVM, 2009).

For storage tanks with over-the-top-fill and no penetrations below the liquid level, Part 193, through adopted portions of NFPA 59A (2001), defines the design spill as the largest flow from any single line that could be pumped into the impounding area with the container withdrawal pumps delivering the full-rated capacity. Based on published failure rates for LNG facilities, the rupture of a storage tank outlet line is on the order of one failure every 20,000 to 30,000 equipment-years ($6x10^{-5}$ to $3x10^{-5}$ failures per 8,760 hours of equipment operation). Because this failure rate applies to a design spill that is specified by Part 193, we believe it can be used as a threshold for determining single accidental leakage sources for impounding areas serving liquefaction process and transfer areas. Selecting a design spill based on equipment failure rates equivalent to the failure specified by Part 193 for storage tanks provides a consistent quantitative basis for design spills. DOT concurred with this approach for Part 193 calculations.[10]

As design spills vary depending on the hazard (vapor dispersion, overpressure or radiant heat), the specific design spills used for the Downeast siting analysis are discussed under "Vapor Dispersion Analysis" and "Thermal Radiation Analysis" in this section.

Table 4.12.5-2: Equipment Failure Rates

Type of Failure	Failures per equipment-year
Cryogenic Storage Tanks (General)	
Rupture of Storage Tank Outlet Line	3E-5 (criteria)
Single Containment Atmospheric Storage Tanks	
Catastrophic Failure of Inner Tank (Rupture)	5E-6 per tank
Catastrophic Failure of Tank Roof	1E-4 per tank
Release from a hole with effective diameter of 1m (~3ft)	8E-5 per tank
Release from a hole with effective diameter of 0.3m (~1ft)	2E-4 per tank
Release from a hole with effective diameter of 0.01m (0.4in)	1E-4 per tank
Double Containment Atmospheric Storage Tanks	
Catastrophic Failure of Inner Tank (Rupture)	5E-7 per tank
Catastrophic Failure of Tank Roof	1E-4 per tank
Release from a hole with effective diameter of 1m (~3ft)	1E-5 per tank
Release from a hole with effective diameter of 0.3m (~1ft)	3E-5 per tank
Release from a hole with effective diameter of 0.01m (0.4in)	1E-4 per tank
Full Containment Atmospheric Storage Tanks	
Catastrophic Failure of Inner Tank (Rupture)	1E-8 per tank
Catastrophic Failure of Tank Roof	4E-5 per tank
Release from a hole with effective diameter of 1m (~3ft)	1E-6 per tank
Release from a hole with effective diameter of 0.3m (~1ft)	3E-6 per tank
Release from a hole with effective diameter of 0.01m (0.4in)	1E-4 per tank
Process Vessels, Distillation Columns, Heat Exchangers, & Condensers	
Catastrophic Failure (Rupture)	5E-6 per vessel
Release from a hole with effective diameter of 0.01m (0.4in)	1E-4 per vessel
Truck Transfer	
Rupture of transfer arm	3E-4 per transfer arm
Release from a hole in transfer arm with effective diameter of 10% transfer arm diameter with maximum of 50mm (2-inches)	3E-3 per transfer arm
Rupture of transfer hose	4E-2 per transfer hose
Release from a hole in transfer hose with effective diameter of 10% transfer hose diameter with maximum of 50mm (2-inches)	4E-1 per transfer hose

[10] PHMSA Interpretation: Letter to Mr. Leon A. Bowdoin, Jr., Regarding The Applicability of 49 CFR 193.2059(c) to a Hypothetical Waterfront Liquefied Natural Gas Plant. (February 28, 2012)

Table 4.12.5-2: Equipment Failure Rates	
Ship Transfer	
Rupture of transfer arm	2E-5 per transfer arm
Release from a hole in transfer arm with effective diameter of 10% diameter with maximum of 50mm (2-inches)	2E-4 per transfer arm
Piping (General)	
Rupture at Valve	9E-6 per valve
Rupture at Expansion Joint	4E-3 per expansion joint
Failure of Gasket	3E-2 per gasket
Piping: d< 50mm (2-inch)	
Catastrophic rupture	1E-6 per meter of piping
Release from hole with effective diameter of 25mm (1-inch)	5E-6 per meter of piping
Piping: 50mm (2-inch) ≤d< 149mm (6-inch)	
Catastrophic rupture	5E-7 per meter of piping
Release from hole with effective diameter of 25mm (1-inch)	2E-6 per meter of piping
Piping: 150mm (6-inch) ≤d< 299mm (12-inch)	
Catastrophic rupture	2E-7 per meter of piping
Release from hole with effective diameter of 1/3 diameter	4E-7 per meter of piping
Release from hole with effective diameter of 25mm (1-inch)	7E-7 per meter of piping
Piping: 300mm (12-inch) ≤d< 499mm (20-inch)	
Catastrophic rupture	7E-8 per meter of piping
Release from hole with effective diameter of 1/3 diameter	2E-7 per meter of piping
Release from hole with effective diameter of 10% diameter, up to 50mm (2-inches)	4E-7 per meter of piping
Release from hole with effective diameter of 25mm (1-inch)	5E-7 per meter of piping
Piping: 500mm (20-inch) ≤d	
Catastrophic rupture	2E-8 per meter of piping
Release from hole with effective diameter of 1/3 diameter	1E-7 per meter of piping
Release from hole with effective diameter of 10% diameter, up to 50mm (2-inches)	2E-7 per meter of piping
Release from hole with effective diameter of 25mm (1-inch)	4E-7 per meter of piping

Vapor Dispersion Analysis

As discussed in Section 4.12.2, a large quantity of LNG spilled without ignition would form a flammable vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limit or encountered an ignition source. In order to address this hazard, 49 CFR § 193.2059 requires each LNG container and LNG transfer system to have a dispersion exclusion zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001). Taken together, Part 193 and NFPA 59A (2001) require that flammable vapors either from an LNG tank impoundment or a single accidental leakage source do not extend beyond a facility property line that can be built upon.

Title 49 CFR §193.2059 requires that dispersion distances be calculated for a 2.5 percent average gas concentration (one-half the LFL of LNG vapor) under meteorological conditions which result in the longest downwind distances at least 90 percent of the time. Alternatively, maximum downwind distances may be estimated for stability Class F, a wind speed of 4.5 mph, 50 percent relative humidity, and the average regional temperature.

The regulations in Part 193 specifically approve the use of two models for performing these dispersion calculations, DEGADIS and FEM3A. The use of alternative models is also allowed, but must be specifically approved by the DOT. Although Part 193 does not require the use of a particular source term model, modeling of the spill and resulting vapor production is necessary prior to the use of vapor dispersion models. In the past, applicants have typically used the SOURCE5 program to model the vapor production from an LNG spill.

Based on requests for clarification on the source term requirements of Part 193, the DOT issued two formal interpretations in July of 2010 regarding the regulations under 49 CFR 193.[11] In these interpretations, the DOT stated that:

- SOURCE5 could no longer be used to determine the vapor gas exclusion zone for compliance with § 193.2059 unless the deficiencies identified in the Fire Protection Research Foundation's reports "Evaluating Vapor Dispersion Models for Safety Analysis of LNG Facilities Research Project (April 2007)" and "LNG Source Term Models for Hazard Analysis: A Review of the State-of-the-Art and an Approach to Model Assessment (March 2009)" had been addressed;

- source term models must have a credible scientific basis and must not ignore phenomena which can influence the discharge, vaporization, and conveyance of LNG; and

- an alternative source term model proposed by Downeast was suitable for siting impoundments, but the effects of flashing and jetting (and any other phenomena having a similar influence on the discharge, vaporization, or conveyance of LNG) must be considered in order to comply with § 193.2059.

As a result of these interpretations, alternative dispersion models became necessary in order to examine the effects of jetting, flashing and conveyance of LNG for exclusion

[11] PHMSA Interpretation "Re: Request for Written Interpretation on the Applicability of 49 CFR 193 to Proposed Waterfront Liquefied Natural Gas Plant in the City of Fall River, Massachusetts" (July 7, 2010) and PHMSA Interpretation "Re: Request for Written Interpretation on the Applicability of 49 CFR 193 to Proposed LNG Import Terminal in Robbinston, Maine" (July 16, 2010).

zone calculations. In August 2010, the DOT issued Advisory Bulletin ADB-10-07 to provide guidance on obtaining approval of alternative vapor-gas dispersion models under Subpart B of 49 CFR 193. In October 2011, two dispersion models were approved by DOT for use in vapor dispersion exclusion zone calculations: PHAST-UDM Version 6.6 and Version 6.7 (submitted by Det Norske Veritas) and FLACS Version 9.1 Release 2 (submitted by GexCon).

On May 23, 2012, and October 12, 2012, as supplemented on October 26 and November 13, 2012, Downeast submitted analyses to address the vapor dispersion analysis requirements of Part 193. PHAST 6.7 and FLACS 9.1, with their built-in source term models, were used to calculate dispersion distances. As the 2011 DOT approvals of the alternative dispersion models did not address source term models, we consulted with the DOT on Downeast's submitted PHAST and FLACS source term modeling. Based on our consultation with DOT staff, we conclude that the use of the PHAST flashing and jetting source term models and the use of the FLACS flashing / jetting / pool spread and vaporization source term models are suitable and comply with the siting requirements of Part 193 for this project. As this determination must be made on a project specific basis, this conclusion would need to be revisited for future applications of these source models.

As discussed under "Design Spills" in Section 4.12.5, failure scenarios must be selected as the basis for the Part 193 dispersion analyses. Process conditions at the failure location would affect the resulting vapor dispersion distances. In determining the spill conditions for these leakage sources, process flow diagrams for the proposed design, used in conjunction with the heat and material balance information (i.e., flow, temperature, and pressure), can be used to estimate the flow rates and process conditions at the location of the spill. In general, higher flow rates would result in larger spills and longer dispersion distances; higher temperatures would result in higher rates of flashing; and higher pressures would result in higher rates of jetting and aerosol formation. Therefore, two scenarios may be considered for each design spill:

- The pressure in the line is assumed to be maintained by pumps and/or hydrostatic head to produce the highest rate of flashing and jetting (i.e. flashing and jetting scenario); and

- The pressure in the line is assumed to be depressurized by the breach and/or emergency shutdowns to produce the highest rate of liquid flow within a curbed, trenched, or impounded area (i.e. liquid scenario).

Alternatively, a single scenario for each design spill could be selected if adequately supported with an assessment of the depressurization calculations and/or an analysis of process instrumentation and shutdown logic acceptable to DOT.

In addition, the location and orientation of the leakage source must be considered. The closer a leakage source is to the property line, the higher the likelihood that the vapor cloud would extend off-site. As most flashing and jetting scenarios would not have appreciable liquid rainout and accumulation, the siting of impoundment systems would be driven by liquid scenarios, while siting of remaining portions of the plant would be driven by flashing and jetting scenarios.

Downeast reviewed multiple releases for the liquid scenarios and for the flashing and jetting scenarios. Downeast used the following conditions, corresponding to 49 CFR 193.2059, for the vapor dispersion calculations: ambient temperature of 69°F, relative humidity of 50 percent, wind speed of 4.5 mph, atmospheric stability class of F and a ground surface roughness of 0.03 meter. In addition, a sensitivity analysis to the wind speed and direction was provided to demonstrate the longest predicted downwind dispersion distance in accordance with the PHAST and FLACS Final Decisions. A sensitivity analysis to ground surface roughness was also provided for spills over water.

Downeast accounted for the facility geometry, including the impoundment and trench geometry details as established by available plant layout drawings. Including the plant geometry accounts for any on-site wind channeling that could occur. The releases were initiated after sufficient time had passed in the model simulations to allow the wind profile to stabilize from effects due to the presence of buildings and other on-site obstructions.

In order to address the highest rate of LNG liquid flow (i.e. liquid scenario) into the Process Area Impoundment Basin, and in accordance with table 2.2.3.5 of NFPA 59A (2001) for storage tanks with over-the-top fill and no penetrations below the liquid level, Downeast specified the design spill as a complete rupture of the 20-inch-diameter discharge header with two in-tank pumps running [(4,600 gpm rated flow) x (2 in-tank pumps) = 9,200 gpm]. The simulation indicated that the vapor cloud was limited to the property line. However, given the guillotine break of the line, process conditions, and system curve, we believe the line would depressurize and the design spill should be based on the maximum pump run-out flow rate (5,750 gpm) of the low pressure in-tank pumps. Therefore, we ran a simulation with the maximum pump run-out flow in FLACS. The simulation indicated that although the vapor cloud was larger, the vapor cloud was still limited to the Downeast LNG facility site.

In order to address the highest rate of LNG liquid flow (i.e. liquid scenario) into the Vaporizer Area Impoundment Basin, Downeast specified the design spill as a complete rupture of the 6-inch-diameter vaporizer-inlet line, resulting in a 3,448 gpm spill rate. The simulation indicated that the vapor cloud was limited to the property line. However, the analysis assumed the liquid spilled directly into the trench. If the liquid were to be spilled outside of the trench, the dispersion distance could extend farther as there is more opportunity for the pool to spread before reaching the trench. Therefore, we ran a simulation with the liquid spilled onto the ground outside of the trench based on its trajectory. The simulation indicated that although the vapor cloud was larger, the vapor cloud was still limited to the Downeast LNG facility site.

In order to address the highest rate of LNG liquid flow (i.e. liquid scenario) into the Transfer Area Impoundment Basin, Downeast specified the design spill as a hole equivalent to 1/3 diameter of the 36-inch-diameter transfer line, resulting in a 32,330 gpm spill rate. The simulation indicated that the vapor cloud was limited to the waterway. However, the analysis assumed the liquid spilled directly into the trench. If the liquid were to be spilled outside of the trench, the dispersion distance could extend farther as there is more opportunity for the pool to spread before reaching the trench. Therefore, we ran a simulation with the liquid spilled outside of the trench onto the water. The simulation indicated that although the vapor cloud was larger, the vapor cloud was still limited to the waterway.

In order to address the highest rate of LNG flashing and jetting from piping (i.e. flashing and jetting scenarios), Downeast considered 36 different design spills. Using PHAST as a screening tool, Downeast evaluated these design spills and selected three flashing and jetting design spills for further analysis using FLACS: (1) a 4-inch-diameter release from LNG piping in the dock area; (2) a 6-inch-diameter release from LNG piping in the tank area; and (3) a 3-inch-diameter release from LNG piping in the high pressure pump area. The vapor dispersion results from all the liquid scenarios and flashing and jetting scenarios are shown combined in figure 4.12.5-1.

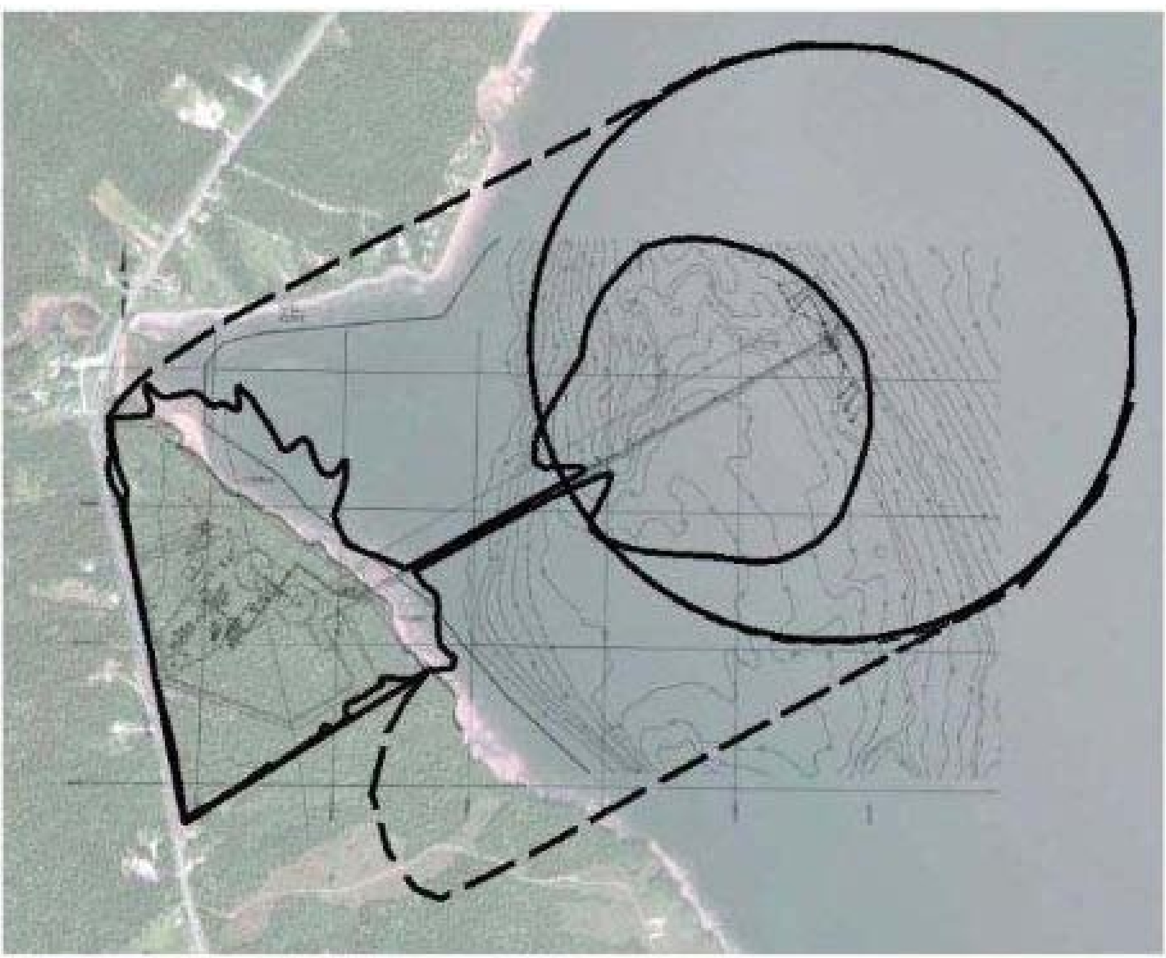
Downeast's simulations indicated that the vapor cloud would be limited to the facility site, the adjacent shoreline and the waterway. The flashing and jetting vapor dispersion results in the tank area and high pressure pump area identified the need for a 20-30 foot fence. Downeast proposes a fence made of impermeable Galvalume panels fastened to galvanized beams and posts to act as a vapor barrier to prevent the LNG vapor from extending beyond the western, northern, and southern property lines. There would be no vapor fence along the eastern property line adjacent to the waterway. In its filings, Downeast presented that the ½ LFL vapor cloud for flashing and jetting cases would remain within the Downeast LNG property or would not extend beyond the property line to the west, north or south considering installation of the vapor barrier.

Downeast stated that the vapor barriers would be routinely inspected by personnel and repaired as necessary. In addition, security patrols would observe the vapor barriers during their regular rounds and report any observed damage. Based on our consultation with the DOT, we believe the mitigation measures proposed for controlling vapor dispersion from these releases would be acceptable under Section 2.2.3.3 of NFPA 59A (2001), as adopted in 49 CFR 193. In order to ensure that the vapor barriers are maintained throughout the life of the facility, **we recommend that:**

- **<u>Prior to construction of the final design,</u> Downeast should file with the Secretary for review and approval by the Director of OEP, procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 CFR 193.2059. This information should be filed a minimum of 30 days before approval to proceed is requested.**

We received comments on Downeast's vapor dispersion exclusion zones extending beyond the shoreline along the eastern property line and over public access routes to intertidal recreation and study areas. The commentor stated that, as Downeast would have no ability to control public access in these areas, the exclusion zones would be in violation of Part 193. After consulting with DOT staff, we conclude that vapor dispersion over the intertidal areas accessed by the public would not be prohibited by Part 193.

The flashing and jetting scenario at the dock area was modeled as a release near the unloading arms, but the release could occur anywhere along the transfer line back to shore. As shown in figure 4.12.5-1, the solid lines represent Downeast's filed dispersion results, while the dashed lines represent potential dispersion results if the release is modeled as occurring anywhere along the transfer line. As shown in the figure, when the release is modeled as occurring anywhere along the transfer line, the vapor cloud could extend onto residential properties at Mill Cove. This would be prohibited by both 49 CFR 193 and NFPA 59A (2001).



—— Downeast filed dispersion results
- - - - Results accounting for release anywhere along transfer line

Figure 4.12.5-1: Vapor Dispersion Exclusion Zones

Overpressure Considerations

As discussed in Section 4.12.2, the propensity of a vapor cloud to detonate or produce damaging overpressures is influenced by the reactivity of the material, the level of confinement and congestion surrounding and within the vapor cloud, and the flame travel distance. It is possible that the prevailing wind direction may cause the vapor cloud to travel into a partially confined or congested area.

As adopted by Part 193, Section 2.1.1 of NFPA 59A (2001) requires an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility be considered. As discussed under “Overpressures” in Section 4.12.2, unconfined LNG vapor clouds would not be expected to produce damaging overpressures. The presence of heavier hydrocarbons influences the propensity for a detonation or deflagration with damaging overpressures. Less processed product with greater amounts of heavier hydrocarbons is more sensitive to detonation. LNG facilities have typically imported LNG with methane concentrations ranging from 89 percent to 96 percent with occasional imports as low as 86 percent. The Downeast LNG import facility would be designed to receive LNG with methane concentrations as low as 87 percent. These compositions are not in the range shown to exhibit overpressures and flame speeds associated with high-order explosions and detonations.

The Coast Guard studies referenced under “Overpressures” in Section 4.12.2 indicated overpressures of 4 bar and flame speeds of 35 m/s (meters per second) were produced from vapor clouds of 86 percent to 96 percent methane in near stoichiometric proportions using exploding charges as the ignition source. The 4 bar overpressure was the same overpressure produced during the calibration test involving exploding the charge ignition source alone, so it remains unclear that the overpressure was attributable to the vapor deflagration. However, unconfined methane vapor clouds ignited with low energy ignition sources have been shown to produce flame speeds ranging from 5.2 to 7.3 m/s, which is much less than the flame speeds associated with explosions or detonations.

Additional tests were conducted to study the influence of confinement and congestion on the propensity of a vapor cloud to detonate or produce damaging overpressures. The tests used obstacles to create a partially confined and turbulent scenario, but found that flame speeds developed for methane were not significantly higher than the unconfined case and were not in the range associated with detonations.

Given the LNG compositions which would be handled onsite, potential ignition sources, and the expected vapor dispersion characteristics, damaging overpressures would not be expected to occur from ignition of an unconfined vapor cloud. However, ignition of a confined vapor cloud could result in higher overpressures. In order to prevent such an occurrence, buildings are typically located away from process areas containing flammable materials. Furthermore, as required by our recommendation in Section 4.12.3, Downeast would need to demonstrate that all areas are adequately covered by hazard detection devices. A preliminary evaluation of the Downeast facility indicates the only enclosed buildings within the facility would be the administrative building, control room building, and electrical switchgear building. In order to reduce the likelihood of flammable vapors dispersing into these buildings, Downeast proposes to pressurize these buildings, elevate the heating, ventilation, and air conditioning (HVAC) intakes above the maximum height of any modeled flammable vapor cloud, and install a flammable gas detector at the HVAC intake to initiate an alarm and shutdown of the HVAC blower upon detection of 20 percent LFL gas concentrations. Based on our consultation with the DOT, we conclude the proposed mitigation measures would be acceptable under Part 193.

After the 2009 draft EIS was issued, we received comments on whether the vapor fences would cause a confinement and potentially result in damaging overpressures from an ignited vapor cloud. The 30-foot and 25-foot tall vapor fences are nearly 80 feet apart where the two run parallel and closest to each other at the western property line. This separation distance is more than adequate enough to prevent any pressure build-up given the lack of congestion between the vapor fences.

Thermal Radiation Analysis

As discussed in Section 4.12.2, if flammable vapors are ignited, the deflagration could propagate back to the spill source and result in a pool fire causing high levels of thermal radiation (i.e., heat from a fire). In order to address this, 49 CFR § 193.2057 requires each LNG container and LNG transfer system to have a thermal exclusion zone in accordance with Section 2.2.3.2 of NFPA 59A (2001). Together, Part 193 and NFPA 59A (2001) specify different hazard endpoints for spills into LNG storage tank containment and spills into impoundments for process or transfer areas. For LNG storage tank spills, there are three radiant heat flux levels which must be considered:

- 1,600 british thermal units per square foot per hour (Btu/ft^2-hr) - This level can extend beyond the facility's property line that can be built upon but cannot include areas that, at the time of facility siting, are used for outdoor assembly by groups of 50 or more persons;

- 3,000 Btu/ft^2-hr - This level can extend beyond the facility's property line that can be built upon but cannot include areas that, at the time of facility siting, contain assembly, educational, health care, detention or residential buildings or structures; and

- 10,000 Btu/ft^2-hr - This level cannot extend beyond the facility's property line that can be built upon.

The requirements for smaller spills from process or transfer areas are more stringent. For these impoundments, the 1,600 Btu/ft^2-hr flux level cannot extend beyond the facility's property line that can be built upon.

Part 193 requires the use of the LNGFIRE3 computer program model developed by the Gas Research Institute to determine the extent of the thermal radiation distances. Part 193 stipulates that the wind speed, ambient temperature, and relative humidity that produce the maximum exclusion distances must be used, except for conditions that occur less than 5 percent of the time based on recorded data for the area.

For its analysis, Downeast calculated thermal radiation distances for the 1,600-, 3,000-, and 10,000-Btu/ft^2-hr incident radiant heat levels for the LNG storage tank using the outer tank's concrete wall diameter (254 feet) as the pool diameter. The flame height was set equal to the top of the concrete wall (142.75 feet). In addition, Downeast calculated thermal radiation distances using LNGFIRE3 for the 1,600-,Btu/ft^2-hr incident radiant heat levels centered on the Process Area Impoundment Basin, the Vaporizer Area Impoundment Basin, and the Transfer Area Impoundment Basin. Downeast selected the following ambient conditions to produce the maximum exclusion distances: wind speeds of 8-16 mph, ambient temperature of 15°F, and 47 percent relative humidity.

For the storage tanks, target heights were set at 0 feet and 52 feet to reflect the minimum and maximum ground level elevation changes from to an offsite area affected by the radiant heat. The elevated target height for the storage tank provides higher thermal radiation intensities as the target would be closer to the elevated fire. For the impoundments, target heights were set at 0 feet as the ground level elevation changes were minimal from the impoundments to offsite areas affected by the radiant heat. The resulting maximum thermal radiation distances are shown in table 4.12.5-3, figure 4.12.5-2 and figure 4.12.5-3.

Table 4.12.5-3: Thermal Radiation Exclusion Zones for Impoundment Basins

Flux Level (Btu/ft^2-hr)	Full Containment Tank Outer Containment (ft)*	Process Area Impoundment Basin (ft)*	Vaporizer Area Impoundment Basin (ft)*	Transfer Area Impoundment Basin (ft)*
10,000	429	58	38	194
3,000	741	113	96	268
1,600	950	137	115	322
*from center of impoundment				

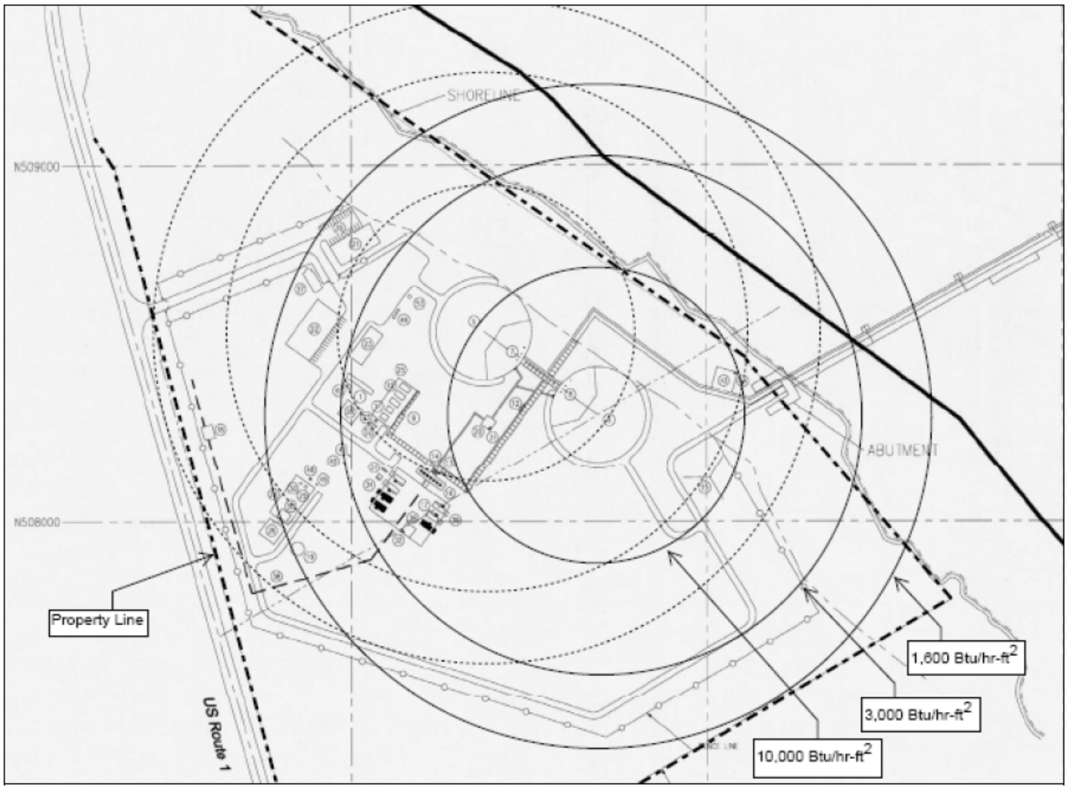


Figure 4.12.5-2 Thermal Radiation Exclusion Zones for Storage Tanks

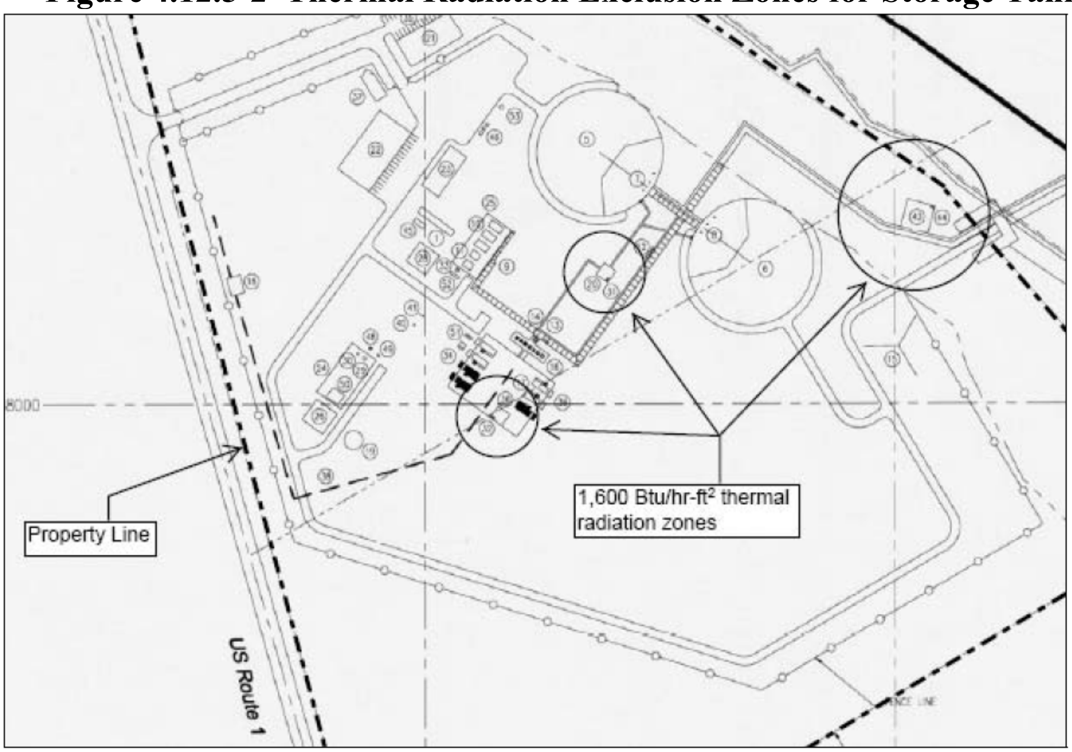


Figure 4.12.5-3 Thermal Radiation Exclusion Zones for Impoundment Basins

As shown in figure 4.12.5-2, both the 10,000-, and 3,000-Btu/ft^2-hr heat flux for the LNG storage tanks would remain within the facility property lines. The 1,600 Btu/ft^2-hr flux level would extend beyond the facility property line onto US Route 1, which, at the time of siting, is not an area we expect to be used for outdoor assembly by groups of 50 or more persons. Consequently, based on consultation with DOT staff, we conclude that the thermal radiation exclusion zones for the LNG storage tanks would meet the requirements specified by Part 193. Although not a factor in our determination, we note the vapor fences around the facility would reduce the radiant heat beyond the property line, but cannot be accounted for by the LNGFIRE3 model.

As shown in figure 4.12.5-3, the 1,600 Btu/ft^2-hr heat flux for the Process Area Impoundment Basin and the Vaporizer Area Impoundment Basin would remain within the facility property lines. The 1,600 Btu/ft^2-hr heat flux for the Transfer Area Impoundment Basin would extend beyond the facility property line over portions of the shoreline and waterway. We do not believe this is a property line that can be built upon. After consultation with DOT staff, we conclude that the thermal radiation exclusion zones for the Process Area Impoundment Basin; the Vaporizer Area Impoundment Basin; and the Transfer Area Impoundment Basin would meet the requirements specified by Part 193.

The proposed layout of the facility would also meet the NFPA 59A (2001) separation requirements of a distance equal to 0.7 times the tank diameter between the storage tank and the property line (178 feet for the tank design under consideration). However, the 10,000 Btu/ft^2-hr incident heat flux for the LNG storage tanks would extend over occupied buildings, such as the main control building, administrative building, and maintenance building, and over equipment that is critical to the safe shutdown and operation of emergency equipment, such as the power distribution building transformers and emergency generator. In addition, the 3,000 Btu/ft^2-hr incident heat flux for the Vaporizer Area Impoundment Basin would extend over the vaporizers, high pressure pumps, and associated equipment. Although there are no provisions within Part 193 or NFPA 59A (2001) which would prohibit this layout, we do not consider this to be appropriate design practice. As a result, **we recommend:**

- **<u>Prior to construction of the final design,</u> Downeast should file the following information:**

  a. an evaluation that justifies the location of occupied buildings, including the main control building, administration building, and maintenance building, or a final design that relocates the occupied buildings or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft^2-hr at occupied buildings.

b. **an evaluation that justifies the location of equipment that is critical to the safe shutdown and operation of emergency equipment, including the power distribution building transformers and emergency generator, or a final design that relocates the equipment or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft^2-hr at the these locations.**

c. **an evaluation that justifies the location of the vaporizers, high pressure pumps, and associated equipment, or a final design that relocates the equipment or impoundment, so that the radiation from a fire in the vaporizer spill impoundment would be less than 3,000 Btu/ft^2-hr at the vaporizer and high pressure pump equipment.**

After the 2009 draft EIS was issued, we received comments on the suitability of LNGFIRE3 in light of research conducted by Sandia National Laboratories (Sandia). In 2007, the DOE contracted Sandia to develop information for assessing the potential impacts associated with large LNG spills on water. The results of this study were released by DOE in the report "Liquefied Natural Gas Safety Research Report to Congress," dated May 2012. Using data gathered from these tests and earlier methane gas burner tests, Sandia developed recommendations on parameters, including mass burning rate, pool fire flame height, surface emissive power, and atmospheric transmissivity, appropriate for use in solid flame models for pool fires over water. We examined the effect of altering the LNGFIRE3 model to incorporate Sandia's recommendations regarding LNG pool fire modeling over water and on data provided by the largest LNG pool fire tests on land (Gaz de France Montoir tests) or water (Phoenix tests).[12] Our conclusions were that LNGFIRE3, as currently prescribed by 49 CFR 193, is appropriate for modeling thermal radiation from LNG pool fires on land and is suitable for use in siting on-shore LNG facilities.

Commentors also questioned the effect of higher wind speeds on flame tilt and flame drag at higher elevations. As part of our evaluation of LNGFIRE3, we examined the effect of higher wind speeds for fires at higher elevations (e.g. storage tank roof top fires). Accounting for these effects would result in a less than 3 percent increase to the 1,600 Btu/ft^2-hr zone, which is well within the uncertainty of the model predictions and is not significant enough to invalidate the thermal radiation modeling results.

Commentors raised further concerns on the structural integrity of storage tanks during a storage tank fire. Assuming the storage tank outer containment progressively failed as

[12] "Recommended Parameters for Solid Flame Models for Land Based Liquefied Natural Gas Spills," Issued January 23, 2013 in Docket AD13-4-000 (eLibrary Accession Number: 20130123-4002).

the fire burned (similar to fires in metal storage tanks), there would be a less than 2 percent increase to the 1,600 Btu/ft^2-hr zone, which is well within the uncertainty of the model predictions and is not significant enough to invalidate the thermal radiation modeling results.

4.12.6 Facility Security

Title 49, CFR, Part 193, Subpart J – Security, specifies security requirements for the onshore component of LNG facilities. This subpart includes requirements for conducting security inspections and patrols, liaison with local law enforcement officials, design and construction of protective enclosures, lighting, monitoring, alternative power sources, and warning signs. Security at the facility would be provided by both active and passive systems. The entire site would be surrounded by a protective enclosure (i.e., a fence) with sufficient strength to deter unauthorized access. The enclosure would be illuminated with not less than 2.2 lux between sunset and sunrise. Intrusion detection systems and day/night camera coverage would identify unauthorized access. A separate security staff would conduct periodic patrols of the plant, and screen visitors and contractors. The security staff may also assist in maintaining security of the marine terminal during cargo unloading.

In addition to the requirements of Part 193, there are also requirements for maintaining security of a marine terminal contained in Coast Guard regulations. Title 33, CFR, Part 105, as authorized by the Maritime Transportation Security Act (MTSA) of 2002, requires all terminal owners and operators to submit a Facility Security Assessment and a Facility Security Plan to the Coast Guard for review and approval. Some of the responsibilities of the applicant include, but are not limited to:

- designating an Facility Security Officer with a general knowledge of current security threats and patterns, risk assessment methodology, and the responsibility for implementing the Facility Security Assessment and Facility Security Plan and performing an annual audit for the life of the project;

- conducting a Facility Security Assessment to identify site vulnerabilities, possible security threats and consequences of an attack, and facility protective measures;

- developing a Facility Security Plan based on the Facility Security Assessment, with procedures for: responding to transportation security incidents; notification and coordination with local, state, and federal authorities; prevention of unauthorized access; measures and equipment to prevent or deter dangerous substances and devices; training; and evacuation;

- implementing scalable security measures to provide increasing levels of security at increasing maritime security levels for facility access control, restricted areas, cargo handling, vessel stores and bunkers, and monitoring;

- ensuring the Transportation Worker Identification Credential program is properly implemented; and

- reporting all breaches of security and security incidents to the National Response Center.

If the project is authorized by the Commission, 33 CFR 105 would require Downeast to submit a Facility Security Plan to the Coast Guard for review and approval before commencement of operations.

The LNG carriers which would deliver LNG to the proposed facility would also need to comply with various U.S. and international security requirements. The International Maritime Organization (IMO) adopted the *International Ship and Port Facility Security Code* (ISPS Code) in 2003. The ISPS Code requires both ships and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against ships; improve security aboard ships and ashore; and reduce the risk to passengers, crew, and port personnel on board ships and in port areas. All LNG vessels, as well as other cargo vessels 500 gross tons and larger, and ports servicing those regulated vessels, must adhere to the IMO standards. Some of the IMO requirements for ships are as follows:

- ships must develop security plans and have a Vessel Security Officer;

- ships must have a ship security alert system. These alarms transmit ship-to-shore security alerts identifying the ship, its location, and indication that the security of the ship is under threat or has been compromised;

- ships must have a comprehensive security plan for international port facilities, focusing on areas having direct contact with ships; and

- ships may have equipment onboard to help maintain or enhance the physical security of the ship.

In 2002, the MTSA was enacted by the U.S. Congress and aligned domestic regulations with the maritime security standards of the ISPS Code and the *International Convention for the Safety of Life at Sea* (SOLAS). The resulting Coast Guard regulations, contained in 33 CFR 104, require vessels to conduct vulnerability assessments and develop corresponding security plans. All LNG carriers servicing the facility would have to comply with the MTSA requirements and associated regulations while in U.S. waters.

4.12.7 LNG Carriers

Since 1959, ships have transported LNG without a major release of cargo or a major accident involving an LNG vessel There are more than 370 LNG carriers in operation routinely transporting LNG between more than 100 import/export terminals currently in operation worldwide. Since U.S. LNG terminals first began operating under FERC jurisdiction in the 1970s, there have been more than 2,600 individual LNG ship arrivals at terminals in the U.S. For the past 40 years, LNG shipping operations have been safely conducted in U.S. ports and waterways.

4.12.7.1 Design and Operating Requirements

The LNG carriers used to import and export LNG to and from the United States would be constructed and operated in accordance with the IMO's *Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk*, the SOLAS, and 46 CFR 154, which contains the United States safety standards for vessels carrying liquefied natural gas in bulk.

As required by the IMO's conventions and design standards, hold spaces and insulation areas on an LNG carrier must be equipped with gas detection and low temperature alarms. These devices monitor for leaks of LNG into the insulation between primary and secondary LNG cargo tank barriers. In addition, hazard detection systems must also be provided to monitor the hull structure adjacent to the cargo tank, compressor rooms, motor rooms, cargo control rooms, enclosed spaces in the cargo area, specific ventilation hoods and gas ducts, and air locks.

In 1993, amendments to the IMO's *Code for the Construction and Equipment of Ships Carrying Dangerous Chemicals in Bulk* required all vessels to have monitoring equipment with an alarm facility which is activated by detection of over-pressure or under-pressure conditions within a cargo tank. In addition, cargo tanks must be heavily instrumented, with gas detection equipment in the hold and inter-barrier spaces, temperature sensors, and pressure gauges. LNG carriers are to be equipped with a firewater system with the ability to supply at least two jets of water to any part of the deck in the cargo area and parts of the cargo containment and tank covers above-deck. A water spray system is also available for cooling, fire prevention, and crew protection in specific areas. In addition, certain areas of LNG carriers are fitted with dry chemical powder-type extinguishing systems and carbon dioxide smothering systems for fighting fires. Fire protection must include the following systems:

- a water spray (deluge) system that covers the accommodation house control room and all main cargo valves;

- a traditional firewater system that provides water to fire monitors on deck and to fire stations found throughout the vessel;

- a dry chemical fire extinguishing system for hydrocarbon fires; and
- a carbon dioxide system for protecting machinery including the ballast pump room, emergency generators, and compressors.

All LNG vessels entering U.S. waters are required to possess a valid IMO Certificate of Fitness and either a Coast Guard Certificate of Inspection (for U.S. flag vessels) or a Coast Guard Certificate of Compliance (for foreign flag vessels). These documents certify that the vessel is designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG carriers under Title 46, CFR, Part 154. Vessels navigating Canadian waters would have to comply with the requirements set out by the Transport Canada with respect to certification, safety inspections and other regulations (SENES, 2007).

4.12.7.2 Hazards Resulting from Accidents

A review of the history of LNG maritime transportation indicates that there has not been a serious accident at sea or in a port which resulted in a spill due to rupturing of the cargo tanks. However, insurance records, industry sources, and public websites identify a number of incidents involving LNG vessels, including minor collisions with other vessels of all sizes, groundings, minor LNG releases during cargo unloading operations, and mechanical/equipment failures typical of large vessels. Some of the more significant occurrences, representing the range of incidents experienced by the worldwide LNG vessel fleet, are described below:

- **El Paso Paul Kayser** grounded on a rock in June 1979 in the Straits of Gibraltar during a loaded voyage from Algeria to the United States. Extensive bottom damage to the ballast tanks resulted; however, no cargo was released because no damage was done to the cargo tanks. The entire cargo of LNG was subsequently transferred to another LNG vessel and delivered to its U.S. destination.

- **Tellier** was blown by severe winds from its docking berth at Skikda, Algeria in February 1989 causing damage to the loading arms and the vessel and shore piping. The cargo loading had been secured just before the wind struck, but the loading arms had not been drained. Consequently, the LNG remaining in the loading arms spilled onto the deck, causing fracture of some plating.

- **Mostefa Ben Boulaid** had an electrical fire in the engine control room during unloading at Everett, Massachusetts. The ship crew extinguished the fire and the ship completed unloading.

- **Khannur** had a cargo tank overfill into the vessel's vapor handling system on September 10, 2001, during unloading at Everett, Massachusetts. Approximately 100 gallons of LNG were vented and sprayed onto the protective decking over the cargo tank dome, resulting in several cracks. After inspection by the Coast Guard, the Khannur was allowed to discharge its LNG cargo.

- **Mostefa Ben Boulaid** had LNG spill onto its deck during loading operations in Algeria in 2002. The spill, which is believed to have been caused by overflow rather than a mechanical failure, caused significant brittle fracturing of the steelwork. The vessel was required to discharge its cargo, after which it proceeded to dock for repair.

- **Norman Lady** was struck by the USS Oklahoma City nuclear submarine while the submarine was rising to periscope depth near the Strait of Gibraltar in November 2002. The 87,000 cubic meter (m^3) LNG vessel, which had just unloaded its cargo at Barcelona, Spain, sustained only minor damage to the outer layer of its double hull but no damage to its cargo tanks.

- **Tenaga Lima** grounded on rocks while proceeding to open sea east of Mopko, South Korea due to strong current in November 2004. The shell plating was torn open and fractured over an approximate area of 20 by 80 feet, and internal breaches allowed water to enter the insulation space between the primary and secondary membranes. The vessel was refloated, repaired, and returned to service.

- **Golar Freeze** moved away from its docking berth during unloading on March 14, 2006, in Savannah, Georgia. The powered emergency release couplings on the unloading arms activated as designed, and transfer operations were shut down.

- **Catalunya Spirit** lost propulsion and became adrift 35 miles east of Chatham, Massachusetts on February 11, 2008. Four tugs towed the vessel to a safe anchorage for repairs. The Catalunya Spirit was repaired and taken to port to discharge its cargo.

Although the history of LNG shipping has been free of major incidents, and no incidents have resulted in significant quantities of cargo being released, the possibility of an LNG spill from a vessel over the duration of the proposed project must be considered. If an LNG spill were to occur, the primary hazard to the public would be from radiant heat from a pool fire. If an LNG release were to occur without ignition, an ignitable gas cloud could form and also present a hazard. Historically, the events most likely to cause a significant release of LNG were a vessel casualty such as:

- a grounding sufficiently severe to puncture an LNG cargo tank;
- a vessel colliding with an LNG vessel in transit;
- an LNG vessel alliding[13] with the terminal or a structure in the waterway; or
- a vessel alliding with an LNG vessel while moored at the terminal.

To result in a spill of LNG, any of the above events would need to occur with sufficient impact to breach an LNG vessel's double hull and cargo tanks. All LNG vessels used to deliver LNG to the proposed project would have double-hull construction, with the inner and outer hulls separated by about 10 feet. Furthermore, the cargo tanks are normally separated from the inner hull by a layer of insulation approximately 1-foot thick.

As a result, many grounding incidents severe enough to cause a cargo spill on a single-bottom oil tanker would be unable to penetrate both inner and outer hulls of an LNG vessel. An earlier Federal Power Commission (predecessor to the FERC) study estimated that the double bottom of an LNG vessel would be sufficient to prevent cargo tank penetration in about 85 percent of the cases that penetrated a single-bottom oil tanker. Previous incidents with LNG vessels have primarily involved grounding, and none of these have resulted in the breach of the double hull and subsequent release of LNG cargo. The likelihood of an LNG vessel sustaining cargo tank damage in a collision would depend on several factors:

- the displacement and construction of both the struck and striking vessels;
- the velocity of the striking vessel and its angle of impact with the struck vessel; and
- the location of the point of impact.

The Federal Power Commission study estimated that the additional protection afforded by the double hull would be effective in low-energy collisions; overall, it would prevent cargo tank penetration in about 25 percent of the cases that penetrated a single-hull oil tanker.

In 1995, to assist the Coast Guard in San Juan, Puerto Rico, EcoEléctrica L.P. prepared an analysis of the damage that could result from an oil tanker striking an LNG vessel at berth (FERC, 1996). The analysis assumed a 125,000 m^3 LNG vessel and an 82,000-

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[13] "Allision" is the action of dashing against or striking upon a stationary object (for example, the running of one ship upon another ship that is docked) – distinguished from "collision," which is used to refer to two moving ships striking one another.

dead-weight-ton tanker carrying number 6 fuel oil without tug assistance. The analysis determined the minimum striking speed to penetrate the cargo tanks of an LNG vessel for a range of potential collision angles. Table 4.12.7.2-1 presents the resulting minimum striking speeds for the two principal cargo systems.

Table 4.12.7.2-1: Minimum Striking Speed to Penetrate LNG Cargo Tanks

Angle of Impact	Minimum Striking Speed (knots)	
	Spherical Tanks	Membrane Tanks
Greater than 60 degrees	4.5	3.0
45 degrees	6.3	4.0
30 degrees	9.0	6.0
15 degrees	18.0	12.0

For membrane tanks, the critical beam-on striking speed was 3.0 knots; for spherical tanks, the critical on-beam speed was 4.5 knots. For both containment types, lower angles of impact result in much greater minimum striking speeds to penetrate LNG cargo tanks. In the July/August 2002 issue of *LNG Journal*, the General Manager of the Society of International Gas Tanker and Terminal Operators provided a table that indicated the critical speed necessary for a 20,000-ton vessel to puncture the outer hull of an LNG vessel was 7.3 knots. For a 93,000-ton vessel, the impact speed was 3.2 knots. In neither case does such an impact result in damage to the LNG cargo containment system, nor does it result in a release of LNG.

A more recent significant work in analyzing the potential for an LNG vessel breach was released by the DOE in December 2004. Sandia conducted the research and wrote the report entitled, *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water* (2004 Sandia Report). The 2004 Sandia Report included an LNG cargo tank breach analysis using modern finite element modeling and explosive shock physics modeling to estimate a range of breach sizes for both credible accidental and intentional LNG spill events. Accidental breaching evaluations were based on finite element modeling of collisions of double-hulled oil tankers similar in size and design to LNG ships. The analysis of accidental events found that groundings, collisions with small vessels, and low-speed (less than 7 knots) collisions with large vessels striking at 90 degrees could cause minor vessel damage but would not result in a cargo spill. This is due to the protection provided by the double-hull structure, the insulation layer, and the primary cargo tank of an LNG vessel. High-speed (12 knots) collisions with large vessels striking at 90 degrees were found to potentially cause cargo tank breach areas of from 0.5 to 1.5 meters squared (m^2).

The possibility of a LNG release due to an accident, such as a collision or grounding, is considered minimal. In addition, current operational procedures in use by the Coast Guard, such as managing ship traffic, coordinating ship speeds, and active ship control in inner and outer harbors, would also further reduce the potential of LNG spill from accidental causes.

4.12.7.3 Hazards Resulting from Intentional Acts

The 2004 Sandia Report included an LNG cargo tank breach analysis, using modern finite element modeling and explosive shock physics modeling to estimate a range of breach sizes for credible intentional LNG spill events involving LNG carriers up to 145,000 m^3 in capacity. The events considered for intentional acts were based on intelligence and historical data, and ranged from sabotage and hijacking to other types of physical attacks. Physical attacks included those documented to have occurred to several types of international shipping vessels, including attacks with small missiles and rockets, and attacks with bulk explosives.

For intentional scenarios, the size of the cargo tank hole depends on the location of the ship and source of threat. Intentional breach areas were estimated to range from 2 to 12 m^2. In most cases, an intentional breaching scenario would not result in a nominal hole area of more than 5 to 7 m^2, which is a more appropriate range to use in calculating potential hazards from spills. These hole sizes are equivalent to circular hole diameters of 2.5 and 3 meters.

The 2004 Sandia Report evaluated cascading damage due to brittle fracture from exposure to cryogenic liquid or fire-induced damage to foam insulation. While possible under certain conditions, the cascading damage was found to not likely involve more than two or three cargo tanks. Cascading events were expected to increase the fire duration but not to significantly increase the overall fire hazard.

The 2004 Sandia Report also included guidance on risk management for intentional spills, based on the findings that the most significant impacts to public safety and property exist within approximately 500 meters (1,640 feet) of a spill due to thermal hazards from a fire, with lower public health and safety impacts beyond 1,600 meters (approximately 1 mile). Large un-ignited LNG vapor releases were found to be unlikely, but could extend from nominally 2,500 meters (8,200 feet) to a conservative maximum distance of 3,500 meters (2.2 miles) for an intentional spill.

In 2008, the DOE released another study prepared by Sandia, entitled *Breach and Safety Analysis of Spills Over Water from Large Liquefied Natural Gas Carriers, May 2008* (2008 Sandia Report). The 2008 Sandia Report assessed the scale of possible hazards for newer LNG vessels with capacities up to 265,000 m^3. Using the same methodology as the 2004 Sandia Report, the 2008 Sandia Report concluded thermal hazard distances would be only 7 - 8 percent greater than those from vessels carrying 145,000 m^3 of LNG, due primarily to the slightly greater height of LNG above the waterline. The 2008 Sandia Report also noted the general design of the larger vessels was similar to the previously analyzed ship designs and, for near-shore facilities, the calculated breach size for intentional scenarios would remain the same. Overall, the 2008 Sandia Report maintained the same impact zones as with the smaller vessels that were analyzed in the 2004 Sandia Report.

In February 2007, the U.S. Government Accountability Office (GAO) published a report assessing several studies, including the 2004 Sandia Report, that had been conducted on the consequences of an LNG spill resulting from a terrorist attack on an LNG vessel (GAO, 2007). The GAO's panel of experts agreed that the most likely public safety impact of an LNG spill would be the radiant heat from a pool fire and suggested that further study was needed to eliminate uncertainties in the assumptions used in modeling large LNG spills on water. After the GAO report, Congress requested the DOE to further address these research needs. DOE contracted Sandia to conduct a series of large-scale LNG fire and cryogenic damage tests to investigate the larger classes of LNG carriers with capacities up to 260,000 m^3, representative of the largest LNG vessels in operation. Sandia conducted the largest LNG pool fire tests done to date and performed advanced computational modeling and ship simulations between 2008 and 2011.

As in the earlier studies, Sandia worked with marine safety, law enforcement, and intelligence agencies to assess threats and credible intentional acts. Scenarios included attacks with shoulder-fired weapons, explosives, and attacks by aircraft and other boats. Sandia identified several ranges of possible hull breaches ranging from 0.005 m^2 (Very Small) to 15 m^2 (Very Large). Based on the collected pool fire test data and the ship simulations, Sandia concluded that thermal hazard distances to the public from a large LNG pool fire was smaller, by at least 2 to 7 percent, than the results listed in the 2004 and 2008 Sandia Reports.

In order to more robustly analyze the potential for cascading failure of LNG carrier cargo tanks, Sandia use detailed vessel structural and thermal damage models to simulate the effects to a LNG carrier from a spill. For the large breaches considered, Sandia predicts that as much as 40 percent of the LNG released from the cargo tank would remain within the ship's structure. Due to both the cold temperature of the LNG and the heat from a pool fire, the LNG carrier's structural steel would be degraded. The effects could be significant enough to cause the ship to be disabled, severely damaged, and at risk of sinking.

Although LNG ship design and construction practices render simultaneous, multiple tank failures as extremely unlikely, Sandia concluded that sequential multi-tank spills may be possible. If sequential failures were to occur, they would not increase the size of the area impacted by the pool fire but could increase the duration of the fire hazards. Based on this research, Sandia concluded that use of a nominal one-tank spill, with a maximum of a three-tank spill, as was recommended in the 2004 Sandia report, is still appropriate for estimating hazard distances.

4.12.7.4 Regulatory Requirements for LNG Carrier Operations

The Coast Guard exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the Magnuson Act (50 United States Code [USC] Section 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC Section 1221, et seq.); and the MTSA of 2002 (46 USC Section 701). The Coast Guard is responsible for matters related to navigation safety, carrier engineering and safety standards, and all matters pertaining to the safety of facilities or equipment located in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The Coast Guard also has authority for LNG facility security plan review, approval, and compliance verification as provided in Title 33, CFR, Part 105.

The Coast Guard regulations in 33 CFR 127 apply to the marine transfer area of waterfront facilities between the LNG vessel and the first manifold or valve located inside the containment. Title 33 CFR 127 regulates the design, construction, equipment, operations, inspections, maintenance, testing, personnel training, firefighting, and security of LNG waterfront facilities. The safety systems, including communications, emergency shutdown, gas detection, and fire protection, must comply with the regulations in 33 CFR 127. Under § 127.019, Downeast would be required to submit two copies of its Operations and Emergency Manuals to the Coast Guard Captain of the Port (COTP) for examination.

Both the Coast Guard regulations under 33 CFR 127 and FERC regulations under 18 CFR 157.21, require an applicant who intends to build an LNG import facility to submit a Letter of Intent (LOI) to the Coast Guard at the same time the pre-filing process is initiated with the Commission. Consequently, Downeast initially notified the Coast Guard that it proposed to construct an LNG import terminal in Washington County, Maine and submitted an LOI to the COTP, Sector Northern New England, on December 21, 2005, with LOI amendments submitted on January 6 and February 8, 2006.[14]

As required by its regulations (33 CFR 127.009), the Coast Guard is responsible for issuing a LOR to the FERC regarding the suitability of the waterway for LNG marine traffic with respect to the following items:

- physical location and description of the facility;

[14] FERC regulations requiring the LOI during the pre-filing process were issued in 2005 (70 FR 60440, Oct. 18, 2005) before Downeast LNG initiated the pre-filing process. In 2010, the Coast Guard revised 33 CFR 127 to require submittal of the LOI during the FERC pre-filing period (75 FR 29426, May 26, 2010).

- the LNG vessel's characteristics and the frequency of LNG shipments to or from the facility;

- waterway channels and commercial, industrial, environmentally sensitive, and residential areas in and adjacent to the waterway used by LNG vessels en route to the facility, within 25 kilometers (15.5 miles) of the facility;

- density and character of marine traffic in the waterway;

- locks, bridges, or other manmade obstructions in the waterway;

- depth of water;

- tidal range;

- protection from high seas;

- natural hazards, including reefs, rocks, and sandbars;

- underwater pipes and cables; and

- distance of berthed vessels from the channel and the width of the channel.

In addition to the LOI, 33 CFR 127 and FERC regulations require each LNG project applicant to submit a Waterway Suitability Assessment (WSA) to the cognizant COTP no later than the start of the FERC pre-filing process. Until a facility begins operation, applicants must annually review their WSAs and submit a report to the COTP as to whether changes are required. The WSA must include the following information:

- port characterization;

- risk assessment for maritime safety and security;

- risk management strategies; and

- resource needs for maritime safety, security, and response.

On June 14, 2005, the Coast Guard published a Navigation and Vessel Inspection Circular – *Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic* (NVIC 05-05). The purpose of NVIC 05-05 was to provide the Coast Guard COTPs/Federal Maritime Security Coordinators, members of the LNG industry, and port stakeholders with guidance on assessing the suitability of a waterway for LNG marine traffic. Since 2005, the Coast Guard updated this guidance twice, publishing NVIC 05-08 and NVIC 01-11. The current guidance from the Coast Guard is contained in NVIC 01-11.

As described in 33 CFR 127 and in NVIC 01-11, the applicant develops the WSA in two phases. The first phase is the submittal of the Preliminary WSA, which begins the Coast Guard's review process to determine the suitability of the waterway for LNG marine traffic. The second phase is the submittal of the Follow-On WSA. This document is reviewed and validated by the Coast Guard and forms the basis for the agency's LOR to the FERC.

The Preliminary WSA provides an outline which characterizes the port community and the proposed facility and transit routes. It provides an overview of the expected major impacts LNG operations may have on the port, but does not contain detailed studies or conclusions. This document is used to start the Coast Guard's scoping process for evaluating the suitability of the waterway for LNG marine traffic.

The Follow-On WSA must provide a detailed and accurate characterization of the LNG facility, the LNG tanker route, and the port area. The assessment should identify appropriate risk mitigation measures for credible security threats and safety hazards. The Follow-on WSA provides a complete analysis of the topics outlined in the Preliminary WSA. It should identify credible security threats and navigational safety hazards for the LNG marine traffic, along with appropriate risk management measures and the resources (federal, state, local, and private sector) needed to carry out those measures.

All three NVICs direct the use of the 2004 Sandia Report as the best available information on LNG spills. NVIC 05-08 and NVIC 01-11 also include use of the 2008 Sandia Report. Three concentric Zones of Concern, based on LNG carriers with a cargo carrying capacity up to 265,000 m^3, are used to assess the maritime safety and security risks of LNG marine traffic. The Zones of Concern are:

- <u>Zone 1</u> – impacts on structures and organisms are expected to be significant within 500 meters (1,640 feet). The outer perimeter of Zone 1 is approximately the distance to thermal hazards of 37.5 kiloWatts per square meter (kW/m^2) (12,000 Btu/ft^2-hr) from a pool fire.

- <u>Zone 2</u> – impacts would be significant but reduced, and damage from radiant heat levels are expected to transition from severe to minimal between 500 and 1,600 meters (1,640 and 5,250 feet). The outer perimeter of Zone 2 is approximately the distance to thermal hazards of 5 kW/m^2 (1,600 Btu/ft^2-hr) from a pool fire.

- <u>Zone 3</u> – impacts on people and property from a pool fire or an un-ignited LNG spill are expected to be minimal between 1,600 meters (5,250 feet) and a conservative maximum distance of 3,500 meters (11,500 feet, or 2.2 miles). The outer perimeter of Zone 3 should be considered the vapor cloud dispersion distance to the LFL from a worst case un-ignited release.

> Impacts to people and property could be significant if the vapor cloud reaches an ignition source and burns back to the source.

Once the applicant submits a complete Follow-On WSA, the Coast Guard reviews the document to determine if it presents a realistic and credible analysis of the public safety and security implications from LNG marine traffic in the port. Finally, the Coast Guard issues a LOR. The Coast Guard may also prepare an LOR Analysis (LOR Analysis), which serves as a record of review of the LOR and contains detailed information along with the rationale used in assessing the suitability of the waterway for LNG marine traffic.

4.12.7.5 Downeast's Waterway Suitability Assessment

Downeast submitted a Preliminary WSA for the proposed project to the Coast Guard in December of 2005. In the development of the Follow-On WSA, consultations occured with the Coast Guard, the Area Maritime Security Committee, and other port stakeholders. As part of its assessment of the safety and security aspects of this project, the COTP Sector Northern New England convened safety and security working groups under the umbrella of the Passamaquoddy Bay/Down East Sub-Committee of the Area Maritime Security Committee (LNG Working Group) and Maine and New Hampshire Port Safety Forum, and participated in ad hoc meetings with the regional U.S. and Canadian response and law enforcement communities. The LNG Working Group, as a whole, convened initially in Ellsworth, Maine, in March of 2006, and subsequent meetings were held in Ellsworth and Eastport, Maine, in April and December 2006, respectively. The consultation process included subsequent collaboration with members throughout the WSA review and validation process.

In addition, a Ports and Waterways Safety Assessment (PAWSA) was conducted in October 2006 to provide a baseline for analyses of navigational safety concerns for the Passamaquoddy Bay port area. The PAWSA is a systematic assessment process designed to identify major waterway safety hazards, estimate risk levels, and evaluate potential measures to reduce risk. Participation in the PAWSA was through invitation and was designed to include a broad cross-section of waterway users, port stakeholders, and maritime professionals. Participants included representatives of the marine industry, pilots, tug operators, passenger/ferry operators, commercial fishing and aquaculture industry, environmental groups, state and local officials, local and regional law enforcement, and federal and provincial governments. Canadian government officials, members of the LNG industry, and concerned citizens' groups were on hand to observe the process.

Downeast submitted the Follow-On WSA to the Coast Guard on December 19, 2006. The Follow-On WSA used three concentric Zones of Concern based on LNG carriers with a cargo carrying capacity up to 265,000 m^3 to assess the maritime safety and security risks of LNG marine traffic in Passamaquoddy Bay.[15]

Carrier Routes

Imported LNG could be obtained from exporting terminals throughout the world and delivered by LNG vessels to the proposed terminal. There are 18 countries which provide LNG for export: Abu Dhabi; Algeria; Australia; Brunei; Egypt; Equatorial Guinea; Indonesia; Libya; Malaysia; Nigeria; Norway; Oman; Peru; Qatar; Russia; Trinidad & Tobago; Yemen; and the United States. Downeast has not identified specific source(s) for LNG supplies for the proposed project.

An LNG carrier's transit from sea to the Downeast LNG terminal would follow a circuitous route through Canadian waters.[16] This is virtually the same route as currently used by all deep-draft vessels servicing the Passamaquoddy Bay port area. Deep-draft vessels bound for the ports of Bayside, New Brunswick, or Eastport, Maine, either enter the area via the Gulf of Maine and into Grand Manan Channel, or by transiting Grand Manan Basin into the Bay of Fundy.

While no deep draft vessel routing is currently mandatory for the proposed transit area, Downeast proposes LNG carriers en route to its proposed terminal enter the area via the Grand Manan Channel only. LNG carriers would approach the U.S. coast from the Atlantic Ocean to a point approximately 5 miles southeast of Cutler, Maine and 10 miles northwest of the southern end of Grand Manan Island. From this point, the LNG carrier would turn northeast and roughly parallel the coast of Maine between Cutler, Maine, and Quoddy Head State Park at a distance of about 2 to 3 miles. Along this same segment, the LNG carrier's route would also parallel the northwest coast of Grand Manan Island at a distance of 5 to 9 miles.

The LNG carrier would continue on its northeasterly course into Canadian waters, roughly paralleling the east and northeast coasts of Campobello Island, New Brunswick, to the entrance of Head Harbor Passage. At this point, the LNG carrier would enter Head Harbor Passage. Here it would pass Campobello Island along the island's north shore, then Friar Roads south of Indian Island and Cherry Isle. The carrier would enter U.S.

[15] Downeast LNG's LOI and WSA were provided to the Coast Guard in 2005 prior to the issuance of the 2008 Sandia Report. The Coast Guard's Waterway Suitability Report states that, "based on the conclusions presented in the Sandia Report of May 2008, the sizes of the hazard zones applied in association with the Downeast LNG site are considered applicable to vessels up to a maximum of 265,000 m^3 cargo capacity."

[16] The carrier transit described in this section is from the Coast Guard's January 6, 2009 Waterway Suitability Report for the proposed Downeast LNG facility. The Waterway Suitability Report can be found in Appendix B of the 2009 draft EIS.

waters as it neared Eastport, Maine. It would pass along Eastport's eastern shore, through Western Passage, pass Quoddy, Maine, to the west and Deer Island, New Brunswick to the east. The ship's transit would continue north through Western Passage along the international boundary between Canada and the United States, keeping Deer Island to the right and the Maine coast on the left until turning northwesterly back into U.S. waters opposite Lewis Cove to reach the intended project site near the mouth of the St. Croix River. A typical transit, from the time an LNG carrier would enter Head Harbor Passage to the time it reaches the proposed Downeast LNG terminal, would take approximately two and one half to three and one half hours.

All deep-draft vessel traffic entering the Passamaquoddy Bay port area initially navigate Canadian waters, and then straddle the international boundary throughout their respective transits. The existing scheme for ensuring traffic control involves the full cooperation of the U.S. and Canada, with vessel movements reported to and controlled by "Fundy Traffic," a Canadian Vessel Traffic System (VTS) in St. John, New Brunswick. Twenty four-hour advance notification to Fundy Traffic is required for all vessels transiting this area. The National Vessel Movement Center in the U.S. requires a 96-hour advance notice of arrival for those deep draft vessels calling on U.S. ports.

Once inside the VTS Fundy Zone, all vessels are required to both maintain voice contact with controllers and check in on designated frequencies at established way points. Both Transport Canada and the U.S. Coast Guard administer Port State Control procedures. If a U.S. Port State Control boarding is required prior to a vessel entering a U.S. port, the boarding would need to take place in U.S. waters, most likely at a point south of West Quoddy Head. Pilotage is compulsory for foreign vessels and U.S. vessels under registry in foreign trade when in U.S. waters. All deep draft ships currently entering the shared waterway via Head Harbor Passage and transiting Maine waters to Eastport must employ a U.S. pilot.

As noted earlier, a typical transit would take approximately two and one half to three and one half hours to traverse the over 16.6 nautical miles from Head Harbor Passage to the proposed terminal. Transit speeds for all LNG marine traffic would be approximately 5 to 10 knots depending on the weather, sea state, and vessel traffic in the area.

LNG carriers leaving the terminal would utilize the same transit routes as described above. A small amount of LNG following cargo unloading at the facility would be retained by the LNG carriers. This volume serves as the "heel" and is the minimum amount of LNG used to insulate the vessel's LNG storage tanks and also serves as fuel for the vessel.

Hazard Zones Associated with the Proposed Route

We received numerous comments from Canadian citizens in opposition to the proposed project and concerns in regard to the project's potential impacts on water quality; wildlife habitat; threatened and endangered species; tourism; and commercial fishing. The 2009 draft EIS addressed many of these issues. The comments received in response to the 2009 draft EIS in regard to those concerns will be addressed in a final EIS.

As LNG carriers proceed along the intended track line, Zone 1, the potential area with the most severe impact, would not affect any high population area or public or government centers such as schools, hospitals or transportation infrastructure.[17] However, Zone 1 may overlap any commercial vessel intended for the Port of Bayside as the vessel passes the berthed LNG carriers. Similarly, recreational and fishing vessels may fall within Zone 1, depending on their course. The seasonal ferry crossings connecting Deer Island, New Brunswick and Eastport, Maine and Campobello Island, New Brunswick could fall within Zone 1 as an LNG carrier passes these ferry crossings. Transit of such vessels through a Zone 1 area of concern can be avoided by timing and course changes, if conditions permit.

During the LNG carrier's transit, Zone 1 would encompass portions of Moose Island on the Maine side and Deer Island on the New Brunswick side. This area presents the narrowest point in the entire transit route and the pilots tend to hug the U.S. side of the dogleg, rather than stay in the middle of the channel, in order to avoid the divergent currents common to this portion of the waterway. Although no major military post or camp is situated along the waterway, Coast Guard Station Eastport, a Search and Rescue and Law Enforcement installation, is located on the shore of Eastport and would fall within Zone 1 and/or 2, depending on the actual course taken by the pilots when navigating the bend off Dog Island. When the carriers transit Head Harbor Passage, the northern most edge of Head Harbor and shore side neighboring areas on Campobello Island would fall within Zone 1. When the carriers transit Friar Roads and Western Passage, the western edge of Deer Island Point, New Brunswick, would also fall into this zone.

Zone 2 areas, defined as those where the impact is significant but reduced, include most of Eastport, Kendall Head, and Pleasant Point, Maine. A portion of Route 190, the only vehicle access to and from the City of Eastport, is within Zone 2.

During LNG vessel transits of Head Harbor Passage, all Canadian areas and communities along the northern and westerly edges of Campobello Island such as Brown Head, Wilson's Beach, Windmill Point, and Bald Head would fall within Zone 2. Also within this zone would be the islands off the coast of New Brunswick to include Spruce Island, Sandy Island, Casco Bay Island, Green Island, Pope Island and Indian Island. Zone 2 would also impact land masses along Friar Roads and Western Passage such as West

[17] As discussed in Section 4.12.7.2, the Coast Guard used criteria developed by Sandia to define the outer limits of the hazard zones for assessing potential risks associated with the proposal. The Coast Guard's January 6, 2009 Waterway Suitability Report (WSR) defines the areas along the transit route that fall within each zone.

Deer Isle, New Brunswick communities west of Highway 772, Doctors Cove, Cummings Cove, and Mink Point.

Zone 3 areas, where impacts would be minimal, include all of Moose Island, Pleasant Point, Perry, and Robbinston. Welshpool and all of Northern Campobello Island would fall into Zone 3, as would the communities on the alternate side of Head Harbor Passage. Zone 3 would encompass areas such as Leonardville, Bar Island, and a portion of Southern Deer Island. When LNG vessels navigate Friar Roads and Western Passage, a major portion of western Deer Island would fall within this zone as well.

4.12.7.6 Coast Guard Waterway Suitability Report

On January 6, 2009, the COTP, Sector Northern New England, issued an LOR and a Waterway Suitability Report (WSR) which summarized the Coast Guard's recommended risk mitigation measures, as well as the port community's capabilities.[18]

Based on the results of the assessment of potential risks to navigation safety and maritime security associated with the Downeast proposal[19], the Coast Guard determined the waterway along the proposed carrier transit route would be suitable for the type and frequency of LNG marine traffic associated with this proposed project, provided that the risk mitigation measures defined in the WSR are implemented. The hydrographic characteristics of the waterway are suitable to sustain deep draft vessel movement and the simulation tests and traffic studies confirm the transit and maneuvers are feasible for the design range of LNG carriers anticipated. These measures are further detailed in the WSR and include, among others, the following requirements:

- The development, by Downeast, of standard operating parameters approved by the Coast Guard and coordinated with the Government of Canada to enable the safe and secure movement of LNG tankers through Canadian and U.S. waters, taking into account the need for:

    1) Number and performance capabilities of assist tugs and escort vessels as well as determining appropriate staging areas. The minimum specified number of escort/assist tugs must be employed at all times to escort LNG carriers throughout their transit and during berthing and

[18] At the time the Coast Guard conducted the waterway review, the guidance in NVIC 05-05 used the term WSR as the title for the LOR Analysis. In order to avoid confusion, the Coast Guard decided to continue referring to its final assessment for the Downeast LNG proposal as the WSR, although the WSR term was eliminated in NVIC 05-08 and NVIC 01-11.

[19] We received comments from the House of Commons and Embassy of Canada opposed to the passage of LNG tankers through Head Harbour Passage, which is located within Canadian internal waters.

unberthing. It should be noted that additional requirements for escort tugs may be identified during the emergency response planning process.

2) Identification and implementation of navigation safety upgrades and enhancements, as identified in Downeast's WSA, to include but not limited to: radar, communications interoperability, data buoys, and critical Aids to Navigation.

3) Safe operating parameters and environmental constraints, to include but not limited to: visibility, wind, sea state, currents, and tides.

4) These parameters must include the following:

   - Daylight Transits - Loaded or partially loaded LNG carriers may only transit the waterway during daylight hours. "Daylight" is interpreted as "civil twilight" in which the sun may be below the horizon, but the "horizon is clear and larger stars visible (Dutton's Navigation and Plotting). In practical terms, the horizon, shoreline and receiving berths must be clearly seen under conditions of natural light;

   - Visibility - A minimum of two miles of visibility is required for the movement of LNG vessels in U.S. waters. Since in marginal weather conditions visibility can vary significantly along the route, the decision as to whether sufficient visibility exists, and is likely to continue to exist for the transit, is a judgment call that will be made jointly between the attending pilot(s) and Fundy Traffic, in consultation with and the concurrence of the COTP. The minimum visibility limits must be commensurate with the combined safety and security parameters;

   - Wind – 25 knots is the maximum sustained wind speed (determined during simulation tests), as measured on the vessel, in which an inbound or outbound transit will be allowed to commence. As with visibility, significant variation in wind conditions can exist along the route, and the decision as to whether wind conditions permit a safe transit will be made by the attending pilot(s) in consultation with, and concurrence by, the COTP;

   - Traffic Control – One-way traffic patterns for deep-draft transits will be required and strictly enforced whenever LNG carriers are moving to avoid meeting or passing situations. At the discretion of the attending pilots and in consultation with vessel masters and Fundy Traffic, all vessel transits will be on a first-come, first-served basis, with inbound vessels having priority over outbound;

- Anchoring - There are presently no designated (i.e., anchorages specified in regulation) for the area. However, three locations are routinely used: one located in the Bay of Fundy (controlled by Fundy Traffic) just outside of the transit corridor and to the north of Head Harbor Passage; one in the vicinity of Friars Roads southeast of Eastport; and one inside of Passamaquoddy Bay. LNG vessels will not be allowed to anchor, or hold, in Friar Roads while waiting for a berth – anchoring or holding under this circumstance must occur offshore;

- Loaded, inbound LNG carriers transiting Head Harbor Passage and Western Passage must maintain ample separation distance and uphold, at a minimum, the safety and security zone parameters. The intent of this limitation is to preclude the possibility of incurring overtaking situations and/or the need for holding at, or anchoring in Friar Roads. Non-LNG vessels may anchor in, or hold at Friar Roads while waiting for a vessel proceeding in the opposite direction to transit Head Harbor Passage or Western Passage; and

- With the exception of temporary boarding areas established by and for Coast Guard authorized assets, the anchoring or holding of LNG vessels within Friar Roads is limited to confirmed emergency situations only, such as major mechanical malfunctions and reduced visibility situations following non-forecasted, abrupt weather changes (fog, squalls, etc.) and/or as directed by, and in consultation with, the COTP.

- The development by Downeast, of an ERP required by Section 311 of EPAct 2005, 15 U.S.C § 717b-1(e), approved by the FERC and accepted by the Coast Guard to enable a comprehensive and coordinated response to an LNG emergency, taking into account the need for:

1) In-transit and dockside emergency procedures in the event of fire, mechanical malfunction, allision, grounding, and/or need of safe anchorage or refuge;

2) The potential environmental impact of an LNG release and the identification and acquisition of joint resource needs to respond to the potential release;

3) A contingency response plan specific to LNG and focusing on a layered response approach;

4) Coordinated marine firefighting training and emergency response, with an emphasis on containing and extinguishing LNG fires; and

5) An incident management training and collaborative exercise program.

- Collaboration with all appropriate jurisdictions on a joint, complementary rulemaking to formalize vessel traffic management practices and the establishment and enforcement of comprehensive safety and security zones for the protection of the LNG carrier, alternate waterway users, and area residents, taking into account the need for:

  1) A one-way vessel traffic scheme during transit operations;

  2) Deep-draft vessel tug escorts and assistance services;

  3) Mandatory pilotage throughout the transit route and during docking and undocking evolutions at all ports along the waterway;

  4) Implementation of an Automatic Identification System for all vessels involved in the transport of LNG on this waterway;

  5) Implementation of appropriate vessel speed restrictions; and

  6) Implementation of appropriate environmental operating parameters (e.g. currents, tides, visibility, wind velocity, etc.).

All the safety and security zones associated with the transiting LNG marine traffic would move with the LNG vessel. As stated in the WSR, the average time for the zone to pass any given point would be approximately 18 minutes. Proper voyage planning and paying attention to advanced Broadcasts to Mariners should be used to alleviate potential conflicts with the moving safety and security zones associated with LNG marine traffic.

- Downeast must develop and successfully conduct full mission bridge simulator training for all pilots providing services to LNG carriers. The training must take into account the full spectrum of vessel design and length, cargo carrying capacity, method of propulsion, steering and rudder configuration, thruster arrangements, and maneuvering characteristics for those carriers being considered for charter. In addition, expanded simulator training incorporating the number and design of tug boats having the minimum performance and operating criteria previously outlined, would be required.

- Downeast must develop a Transit Management Plan (TMP) or other document, in consultation with the Coast Guard and other cognizant agencies, that clearly outlines the roles, responsibilities, and specific procedures for the LNG carrier, the LNG terminal, and all federal, state/provincial, and local stakeholders with responsibilities related to the proposed project and/or whose jurisdiction may reasonably be expected to be impacted by a potential navigation safety accident or terrorist attack.

- The applicant must prepare and submit an Operations Manual, as required by 33 C.F.R. § 127.305, an Emergency Manual, as required by 33 C.F.R. § 127.307, and a Facility Security Plan as required by 33 C.F.R. § 105.120 to the COTP Sector Northern New England for review and approval at least 6 months but no more than 12 months before the facility would begin operations.

- The applicant must provide written verification to the Coast Guard of collaboration with and acceptance from the Passamaquoddy Nation, ensuring its jurisdictional interests and public safety and security needs associated with this project are adequately met.

The risk mitigation measures in the WSR also provide that Downeast must determine and comply with all Canadian laws and regulations applicable to safe and secure navigation and the regulation of maritime traffic that comply with customary international law. The Coast Guard indicated that such laws and regulations should not discriminate among foreign ships or in their application have the practical effect of denying, hampering, or impairing the right of non-suspendable innocent passage through an international strait. Moreover, consistent with international law, the Coast Guard will not require compliance with such laws and regulations that apply to the design, construction, manning, or equipment of foreign ships unless they are giving effect to generally accepted international rules or standards.

Based on its review of the WSA, the Coast Guard determined that the Passamaquoddy Bay navigation channel would be suitable for the type and frequency of LNG marine traffic associated with the proposed project. This determination is contingent upon implementation of the recommended measures outlined in the WSR to responsibly manage the maritime safety and security risks. These security measures would be incorporated into the required TMP, which must be developed in consultation with the Coast Guard and other cognizant agencies. This plan would clearly spell out roles, responsibilities, and specific procedures for LNG marine traffic transiting Passamaquoddy Bay up to the terminal, as well as for all agencies involved in implementing security and safety during the operation.

The Coast Guard's LOR is a recommendation on the current status of the waterway to the FERC, the lead agency responsible for siting the on-shore LNG facility. Neither the Coast Guard nor the FERC has authority to require waterway resources of anyone other than the applicant under any statutory authority or under the ERP or the Cost Sharing Plan (see Section 4.12.8). However, if the project is approved and if the appropriate resources are not in place, then neither agency would allow the project to go into operation.[20,21] As the Coast Guard recommended that additional measures beyond those

[20] *Bradwood Landing LLC.*, 124 FERC ¶ 61,257, at PP 60-61 (2008); *AES Sparrows Point LNG, LLC*, 126 FERC ¶ 61,019, at PP 152 (2009).; *Jordan Cove Energy Project, L.P.*, 129 FERC ¶ 61,234, at PP 139 (2009).

proposed by Downeast in the WSA would be needed to responsibly manage the maritime safety and security risks associated with LNG marine traffic, **we recommend that:**

- **Downeast should receive written authorization from the Director of OEP <u>before commencement of service</u> at the LNG terminal. Such authorization would only be granted following a determination that appropriate measures, as recommended by the Coast Guard to ensure the safety and security of the facility and the waterway, have been put into place by Downeast or other parties.**

The Coast Guard regulations in 33 CFR 127 require that applicants annually review WSAs until a facility begins operation. Accordingly, Downeast is required to submit a report to the Coast Guard identifying any changes in conditions, such as changes to the port environment, the LNG facility, or the tanker route, that would affect the suitability of the waterway. Downeast's provided substantiation of its internal review to the Coast Guard on September 13, 2011. In a letter dated November 10, 2011, the Coast Guard responded that the updates did not change the overall port environment, nor did they affect the suitability of the waterway for marine LNG traffic and that the Downeast WSA did not need to be amended at that time. In February 2013, Downeast was in the process of updating its WSA with changed demographic information. The Coast Guard has informed Downeast that any changes to the physical description/layout of the proposed project, modifications to the proposed operation, alterations to the intended transit route, revisions to applied risk management methodologies, and/or changes to identified resource capabilities would need to be provided for Coast Guard review and validation. Once the annual update is submitted, the Coast Guard will determine whether the WSA needs to be amended.

4.12.8 Emergency Response and Evacuation Planning

As required by 49 CFR § 193.2059, Downeast would need to prepare emergency procedures manuals that provide for: a) responding to controllable emergencies and recognizing an uncontrollable emergency; b) taking action to minimize harm to the public including the possible need to evacuate the public; and c) coordination and cooperation with appropriate local officials. Specifically, § 193.2509(b)(3) requires "Coordinating with appropriate local officials in preparation of an emergency evacuation plan…"

Section 3A(e) of the Natural Gas Act, added by Section 311 of EPAct 2005, stipulates that in any order authorizing an LNG terminal, the Commission must require the LNG

[21] As stated in NVIC01-11, the COTP has the authority under the Magnuson Act, the Ports and Waterways Safety Act, the Safety and Accountability for Every Port Act, and the MTSA to prohibit LNG transfer operations or LNG vessel movements as necessary to protect the waterway, port, or marine environment.

terminal operator to develop an ERP in consultation with the Coast Guard and state and local agencies. The Coast Guard's WSR also recommends that that the ERP be developed in consultation with the Coast Guard and other cognizant agencies, plus all federal, state/provincial, and local stakeholders with responsibilities related to the proposed project. The WSR states that, "Additionally, bilateral arrangements to ensure appropriate cross-boundary emergency response capabilities under the existing CANUSLANT[22] agreement would be required," but acknowledges that how the ERP development "process applies to Canada and whether Canadian officials will wish to be involved are issues as yet to be determined." The FERC must approve the ERP prior to any final approval to begin construction. Therefore, **we recommend that**:

- **Downeast should develop an ERP (including evacuation) and coordinate procedures with the Coast Guard; state/provincial, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan should include at a minimum:**

  a. designated contacts with state and local emergency response agencies;

  b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

  c. procedures for notifying residents and recreational users within areas of potential hazard;

  d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

  e. locations of permanent sirens and other warning devices; and

  f. an "emergency coordinator" on each LNG vessel to activate sirens and other warning devices.

The ERP should be filed with the Secretary for review and written approval by the Director of OEP <u>prior to initial site preparation</u>. Downeast should notify the FERC staff of all planning meetings in

[22] Acronym for Canada, United States, Atlantic. CANUSLANT refers to the environmental response protocol is in place between the U.S. and Canada for spills of oil and other noxious substances.

advance and should report progress on the development of its ERP at 3-month intervals.

A number of organizations and individuals have expressed concern that the local community would have to bear some of the cost of ensuring the security and emergency management of the LNG facility and the LNG vessels while in transit and unloading at the berth. Section 3A(e) of the Natural Gas Act (as amended by EPAct 2005) specifies that the ERP must include a Cost-Sharing Plan that contains a description of any direct cost reimbursements the applicants agree to provide to any state and local agencies with responsibility for security and safety at the LNG terminal and in proximity to LNG vessels that serve the facility. Therefore, **we recommend that:**

- **The ERP should include a Cost-Sharing Plan identifying the mechanisms for funding all project-specific security/emergency management costs that would be imposed on state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan should include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. The Cost-Sharing Plan should be filed with the Secretary for review and written approval by the Director of OEP prior to initial site preparation.**

The cost-sharing plan must specify what the LNG terminal operator would provide to cover the cost of the state and local resources required to manage the security of the LNG terminal and LNG vessel, and the state and local resources required for safety and emergency management, including:

- Direct reimbursement for any per-transit security and/or emergency management costs (for example, overtime for police or fire department personnel);

- Capital costs associated with security/emergency management equipment and personnel base (for example, patrol boats, fire fighting equipment); and

- Annual costs for providing specialized training for local fire departments, mutual aid departments, and emergency response personnel; and for conducting exercises.

The cost-sharing plan must include the LNG terminal operator's letter of commitment with agency acknowledgement for each state and local agency designated to receive resources.

4.12.9 Conclusions on Marine Safety

Since 1959, ships have transported LNG without a major release of cargo or a major accident involving an LNG vessel. For the past 40 years, LNG shipping operations have been safely conducted in U.S. ports and waterways. All LNG vessels entering U.S. waters are required to be certified by the Coast Guard as designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG carriers under 46 CFR 154. As a result, the possibility of a LNG release due to an accident, such as a collision or grounding, is considered minimal. In addition, current operational procedures in use by the Coast Guard in U.S. ports, such as managing ship traffic, coordinating ship speeds, and active ship control in inner and outer harbors, further reduce the potential of LNG spill from accidental causes.

Potential results from intentional acts and threats identified by marine safety, law enforcement, and intelligence agencies must also be considered. Such scenarios, including attacks with shoulder-fired weapons, explosives, and attacks by aircraft and other boats, could result in spills from LNG carriers visiting the proposed project. Security procedures for both the facility and the LNG carriers could be used to reduce the potential of an LNG spill from intentional causes. Both the on-shore facility and the LNG carriers would be subject to stringent requirements for security plan development and approval by the Coast Guard under Title 33, CFR, Parts 104 and 105; the MTSA; the ISPS; and SOLAS.

If an LNG spill were to occur along the waterway, the primary hazard to the public would be from radiant heat from a pool fire. In order to assess the maritime safety and security risks of LNG marine traffic travelling to the proposed facility, hazard distances from both accidental and intentional events were estimated for LNG carriers with cargo capacities up to 265,000 m^3. Based on the results of this analysis, the Coast Guard recommended that the waterway along the proposed carrier transit route would be suitable for the type and frequency of LNG marine traffic associated with this proposed project. However, the Coast Guard's conclusion is contingent upon implementation of the recommended measures, outlined in the WSR, to responsibly manage the maritime safety and security risks. If the project is approved and if the appropriate resources were not put into place, then neither the FERC nor the Coast Guard would allow the project to commence service.

C. CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations presented are those of the FERC environmental staff for the revised reliability and safety analysis presented in this Supplement.

1. **Prior to the end of the Supplemental draft EIS comment period**, Downeast shall file a revised Process Area Impoundment Basin design which has the capacity to accommodate the maximum pump run-out flow.

2. **Prior to the end of the Supplemental draft EIS comment period**, Downeast shall file a revised Vaporizer Area Impoundment Basin design which has the capacity to accommodate the maximum pump run-out flow.

Recommendations 3 through 74 shall apply to the Downeast LNG terminal. Information pertaining to these specific recommendations shall be filed with the Secretary for review and written approval by the Director of OEP either: <u>prior to initial site preparation</u>; <u>prior to construction of final design</u>; <u>prior to commissioning</u>; <u>prior to introduction of natural gas or process fluids</u>; or <u>prior to commencement of service</u>, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, shall be submitted as CEII pursuant to 18 CFR 388.112. See CEII, Order No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. ¶31,228 (2006). Information pertaining to items such as: offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements would be subject to public disclosure. All information shall be filed a minimum of 30 days before approval to proceed is requested.

3. Downeast shall develop an ERP (including evacuation) and coordinate procedures with the Coast Guard; state/provincial, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan shall include at a minimum:

   a. designated contacts with state and local emergency response agencies;

   b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

   c. procedures for notifying residents and recreational users within areas of potential hazard;

   d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

   e. locations of permanent sirens and other warning devices; and

   f. an "emergency coordinator" on each LNG vessel to activate sirens and other warning devices.

   The ERP shall be filed with the Secretary for review and written approval by the Director of OEP **prior to initial site preparation**. Downeast shall notify the FERC staff of all planning meetings in advance and shall report progress on the development of its ERP **at 3-month intervals**.

4. The ERP shall include a Cost-Sharing Plan identifying the mechanisms for funding all project-specific security/emergency management costs that would be imposed on state and local agencies. In addition to the funding of direct transit-related security/emergency management costs, this comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. The Cost-Sharing Plan shall be filed with the Secretary for review and written approval by the Director of OEP **prior to initial site preparation**.

5. **Prior to initial site preparation**, Downeast shall provide an Implementation Plan which identifies when Downeast would provide:
   a. quality assurance and quality control procedures for construction activities;
   b. a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems;
   c. an equipment list of the final design which shall include; tag numbers, manufacturer, design pressure and MAWP, design temperature and MDMT, equipment dimensions, design and normal liquid storage capacity; rated and normal flow capacity, rated and normal heating capacity, heat transfer area, motor horsepower and voltage, as applicable;
   d. spill containment system drawings of the final design with dimensions and slopes of curbing, trenches, and impoundments;
   e. electrical area classification drawings of the final design;
   f. drawings and details of all process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system for the final design;
   g. the sizing basis and capacity for the final design of: pressure and vacuum relief valves for major process equipment, vessels, and storage tanks; and vent stacks;
   h. procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3 required by 49 CFR 193;
   i. results of the LNG storage tank hydrostatic test and foundation settlement results;
   j. a commissioning plan; and
   k. a cooldown plan.

6. **Prior to initial site preparation**, Downeast shall file an overall project schedule, which includes the proposed stages of the commissioning plan.

7. **Prior to initial site preparation**, Downeast shall provide procedures for controlling access during construction.

8. **Prior to initial site preparation**, Downeast shall file complete plan drawings and a list of the hazard detection equipment. Plan drawings shall clearly show the location of all detection equipment. The list shall include the instrument tag number, type and location, alarm locations, and shutdown functions of the proposed hazard detection equipment.

9. **Prior to initial site preparation**, Downeast shall provide a technical review of its proposed facility design that:
   a. identifies all combustion/ventilation air intake equipment and the distances to any possible hydrocarbon release (LNG, flammable refrigerants, flammable liquids and flammable gases); and
   b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion equipment whose continued operation could add to or sustain an emergency.

10. **Prior to initial site preparation**, Downeast shall file plan drawings and a list of the fixed and wheeled dry-chemical, fire extinguishing, and other hazard control equipment. Plan drawings shall clearly show the planned location of all fixed and wheeled extinguishers. The list shall include the equipment tag number, type, size, equipment covered, and automatic and manual remote signals initiating discharge of the units.

11. **Prior to initial site preparation**, Downeast shall file facility plans and drawings showing the proposed location of the firewater and high-expansion foam system. Plan drawings shall clearly show the planned location of firewater and high expansion foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, high-expansion foam generator, and sprinkler. The drawings shall also include piping and instrumentation diagrams of the firewater and high expansion foam systems.

12. **Prior to initial site preparation**, Downeast shall file a complete specification of the proposed LNG tank design and installation.

13. **Prior to initial site preparation**, Downeast shall file drawings of the storage tank piping support structure and support of horizontal piping

at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances.

14. **Prior to initial site preparation**, Downeast shall file complete plan drawings of the security fencing and of facility access and egress, including the details of the fence and control access and egress from the pipe trestle and dock.

15. **Prior to construction of the final design,** Downeast shall provide information/revisions related to those responses in their April 10, 2007 filing that state that corrections or modifications would be made to the design. The final design shall specifically address response numbers 2, 8, 10, 13, 15, 23, 24, 25, 26, 27, 30, 31, 33, 34, 38, 51, 54, 56, 59, 61, and 70 using management of change procedures.

16. **Prior to construction of the final design,** Downeast shall file with the Secretary for review and approval by the Director of OEP, procedures to maintain and inspect the vapor barriers provided to meet the siting provisions of 49 CFR 193.2059. This information shall be filed a minimum of 30 days before approval to proceed is requested.

17. **Prior to construction of the final design,** Downeast shall file the following information:

    a. an evaluation that justifies the location of occupied buildings, including the main control building, administration building, and maintenance building, or a final design that relocates the occupied buildings or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft^2-hr at occupied buildings.

    b. an evaluation that justifies the location of equipment that is critical to the safe shutdown and operation of emergency equipment, including the power distribution building transformers and emergency generator, or a final design that relocates the equipment or storage tank, so that the radiation from a storage tank roof top fire would be less than 10,000 Btu/ft^2-hr at the these locations.

    c. an evaluation that justifies the location of the vaporizers, high pressure pumps, and associated equipment, or a final design that relocates the equipment or impoundment, so that the radiation from a fire in the vaporizer spill impoundment would be less than 3,000 Btu/ft^2-hr at the vaporizer and high pressure pump equipment.

18. The **final design** shall include up-to-date PFDs with heat and material balances and P&IDs. The P&IDs shall include the following information:

a. equipment tag number, name, size, duty, capacity, and design conditions;
b. equipment insulation type and thickness;
c. storage tank pipe penetration size or nozzle schedule;
d. piping with line number, piping class specification, size, and insulation type and thickness;
e. piping specification breaks and insulation limits;
f. all control and manual valves numbered;
g. relief valves with set points;
h. drawing revision number and date; and
i. change log that lists and explains the changes made from the approved design.

19. The **final design** shall include a list of all car-sealed and locked valves consistent with the P&IDs.

20. The **final design** of the fixed and wheeled dry-chemical, fire extinguishing hazard control equipment shall identify manufacturer and model.

21. The **final design** shall include an updated fire protection evaluation carried out in accordance with the requirements of NFPA 59A 2001, chapter 9.1.2. The fire protection evaluation shall address measures on the prevention of caustic water from entering the firewater tank.

22. The **final design** shall specify that the design pressure of sendout equipment containing LNG in low pressure service shall be not less than the design pressure of the piping system.

23. The **final design** shall specify that LNG relief valves and LNG drains shall not discharge into the vapor system.

24. The **final design** shall specify that LNG from relief valves and drains is to be returned to storage.

25. The **final design** shall include provision for vehicle access roads to and from the north and south of the LNG pump and vaporizer area.

26. The **final design** of the vapor return system shall include provisions for the addition of LNG transfer pumps to the Jetty Drum D-103. The vapor inlet piping to the drum shall be designed to ensure that all LNG, from the

desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping.

27. The **final design** shall include provisions for the future installation of LNG pumps for the BOG drum.

28. The **final design** shall specify that the vapor inlet piping to the BOG drum shall be designed to ensure that all LNG, from the desuperheater and LNG piping discharging to the drum, cannot back flow to the vapor return piping.

29. The **final design** shall specify that the Low Point Drain Drum is to be equipped to remove residual liquids without personnel accessing the spill containment sump.

30. The **final design** of the Low Point Drain Drum shall include a pressure relief system, to protect the vessel in the event of isolation.

31. The **final design** of the boil-off condenser system shall include a relief valve between the vapor inlet check valve and the fail closed LNG outlet control valve.

32. The **final design** shall include provisions to recycle the boil-off compressor discharge to upstream of the BOG drum desuperheater.

33. The **final design** shall include car-seal or locked closed bypass valves around the intank pump ESD2 discharge valves as opposed to minimum stop set points for ESD2 valves, for cooldown of the 20-inch diameter header and piping.

34. The **final design** shall include a shutoff valve at the suction and discharge of each high pressure pump.

35. The **final design** shall specify that the minimum flow recycle line from the high pressure LNG pumps to downstream of the isolation valve to the LNG storage tanks shall be the same pressure and temperature rating as the piping at the discharge of the high pressure LNG pumps.

36. The **final design** shall include a relief valve or operated vent valve sized for thermal relief at the discharge of each vaporizer, upstream of the isolation valves. This relief valve is in addition to the relief valve specified in NFPA 59A and shall be set at a lower pressure.

37. The **final design** shall include LNG tank fill flow measurement with high flow alarm.

38. The **final design** shall include a discretionary vent valve for each LNG tank, operable through the DCS.

39. The **final design** shall include BOG flow and temperature measurement for each tank.

40. The **final design** shall specify that all ESD valves are to be equipped with open and closed position switches connected to the DCS/SIS.

41. The **final design** shall include a clean agent system in the power distribution building.

42. The **final design** shall include an analysis of the structural integrity of the outer containment of the full containment storage tanks when exposed to a roof tank top fire or adjacent tank top fire.

43. The **final design** shall specify that all drains from high pressure LNG systems are to be equipped with double isolation and bleed valves.

44. The **final design** shall specify that for LNG and natural gas service, branch piping and piping nipples less than 50 millimeters (2 inches), are to be no less than schedule 160 up to the first isolation valve.

45. The **final design** shall specify that piping and equipment that may be cooled with liquid nitrogen is to be designed for liquid nitrogen temperatures, with regard to allowable movement and stresses.

46. The **final design** shall include details of the shut-down logic, including cause and effect matrices for alarms and shutdowns.

47. The **final design** shall include emergency shutdown of equipment and systems activated by hazard detection devices for flammable gas, fire, and cryogenic spills, when applicable.

48. The **final design** shall include details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A.

49. The **final design** shall include details of the air gaps to be installed downstream of all process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that: shall continuously monitor for the presence of a flammable fluid; shall alarm the hazardous condition; and shall shutdown the appropriate systems.

50. The **final design** shall include a HAZOP of the completed design. A copy of the review, a list of the recommendations, and actions taken on the recommendations shall be filed.

51. The **final design** shall include provisions to install high pressure boil-off compression or BOG liquefaction in the event that sendout operation is curtailed, or ceased for a period in excess of thirty days. Details shall include plans and drawings of the BOG recovery system and specifications of the equipment and compressors to be installed.

52. The **final design** shall include provisions to remove LNG from the inlet of the vaporizer due to shutdown sequence.

53. The **final design** shall include a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice required by 49 CFR 193.

54. The **final design** shall include a vent stack dispersion analysis to determine the proper placement of hazard detection devices that ensures venting is done in a safe manner.

55. The **final design** shall specify that the vent stack be equipped with a discharge piece designed for ignited discharge conditions.

56. **Prior to commissioning**, Downeast shall file a copy of the Mechanical Completion Certificate and any documentation (i.e., punch list items) that certifies that the facility is installed and mechanically tested according to the final design and specifications.

57. **Prior to commissioning**, Downeast shall tag all instrumentation and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.

58. **Prior to commissioning**, Downeast shall maintain a name plate database containing photographic documentation of all major equipment.

59. **Prior to commissioning**, Downeast shall file the design details and procedures to record and to prevent the tank fill rate from exceeding the maximum fill rate specified by the tank designer.

60. **Prior to commissioning**, Downeast shall file a tabulated list and complete drawings of the proposed hand-held fire extinguishers. The list shall include the equipment number, type, size, number, and location. Plan drawings shall include the type, size, and number of all hand-held fire extinguishers.

61. **Prior to commissioning**, Downeast shall file Operation and Maintenance procedures and manuals, including safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, and management of change procedures and forms.

62. **Prior to commissioning**, Downeast shall maintain a detailed training log to demonstrate that operating staff has completed the required training.

63. **Prior to commissioning**, Downeast shall file a plan for functional and operational tests of the final design.

64. **Prior to introduction of natural gas or process fluids**, Downeast shall file a copy of the Ready for Cooldown Certificate and any documentation (i.e., punch list items) that certifies the facility is operational and functionally tested according to the final design and specifications.

65. **Prior to introduction of natural gas or process fluids**, Downeast shall file a cooldown plan. During cooldown, Downeast shall report progress on the development of cooldown in daily reports.

66. **Prior to introduction of natural gas or process fluids**, Downeast shall complete all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS and SIS that demonstrates full functionality and operability of the system.

67. **Prior to introduction of natural gas or process fluids**, Downeast shall complete instrumentation functional tests, hazard detection equipment functional tests, and ESD tests.

68. **Prior to introduction of natural gas or process fluids**, hazard control and security components and systems shall be installed and functional.

69. **Prior to introduction of natural gas or process fluids,** Downeast shall complete a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s).

70. **Prior to commissioning**, Downeast shall label equipment with equipment tag number and piping with fluid service and direction of flow in the field in addition to the pipe labeling requirements of NFPA 59A.

71. **Prior to commencement of service**, Downeast shall develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Downeast staff.

72. Downeast shall receive written authorization from the Director of OEP **before commencement of service** at the LNG terminal. Such authorization would only be granted following a determination that appropriate measures, as recommended by the Coast Guard to ensure the safety and security of the facility and the waterway, have been put into place by Downeast or other parties.

73. **Prior to commencement of service**, Downeast shall notify FERC staff of any proposed revisions to the security plan and physical security of the facility.

74. **Prior to commencement of service**, Downeast shall file progress on construction of the LNG terminal in **monthly** reports. Details shall include a summary of activities, problems encountered, contractor non-conformance/deficiency logs, remedial actions taken, and current project schedule. Problems of significant magnitude shall be reported to the FERC **within 24 hours**.

Recommendations 75 though 78 shall apply throughout the life of the facility:

75. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an **annual** basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Downeast shall respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed piping and instrumentation diagrams reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted annual report, shall be submitted.

76. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions, abnormal operating experiences, activities (including ship arrivals/departures, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil-off/flash gas, etc.), and plant modifications including future plans and progress thereof. Abnormalities shall include, but not be limited to: unloading/loading shipping problems, potential hazardous conditions caused by off-site transportation, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, nonscheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner

vessels, vapor or liquid releases, fires involving natural gas and/or from other sources, negative pressure (vacuum) within a storage tank and higher than predicted boiloff rates. Adverse weather conditions and the effect on the facility shall also be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall also be included in the semiannual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance projects at the LNG facility.

77. In the event the temperature of any region of any secondary containment, including imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission shall be notified **within 24 hours** and procedures for corrective action shall be specified.

78. Significant non-scheduled events, including safety-related incidents (e.g., LNG, refrigerant or natural gas releases, fires, explosions, mechanical failures, unusual over pressurization, and major injuries) and security related incidents (i.e., attempts to enter site, suspicious activities) shall be reported to FERC staff. In the event an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to FERC staff **within 24 hours**. This notification practice shall be incorporated into the LNG facility's emergency plan. Examples of reportable LNG or refrigerant related incidents include:

a. fire;

b. explosion;

c. estimated property damage of $50,000 or more;

d. death or personal injury necessitating in-patient hospitalization;

e. release of LNG or refrigerants for five minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;

g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas, refrigerants, or LNG;

h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas, refrigerants, or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices;
i. a leak in an LNG facility that contains or processes gas, refrigerants, or LNG that constitutes an emergency;
j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;
k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operation of a pipeline or an LNG facility that contains or processes gas, refrigerants, or LNG;
l. safety-related incidents to LNG or refrigerant transportation occurring at or en route to and from the LNG facility; or
m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow-up report or follow-up in the upcoming semi-annual operational report. All company follow-up reports shall include investigations results and recommendations to minimize a reoccurrence of the incident.

Appendix A Distribution List

Federal Government – Elected/Appointed Officials

U.S. Representative Michael Michaud, DC
U.S. Representative, Chellie Pingree, ME

Federal Agencies

Advisory Council on Historic Preservation, Office of Federal Agency Programs, Don L. Klima, Director, DC
Airforce Real Property Agency, Jeffrey Blevins, TX
Army Corps of Engineers, Department of Defense, Senior Policy Advisor, Planning and Policy Division
Assistant for Sustainability, Office of Deputy Assistant Secretary of the Army
Bureau of Oceans & International Environmental & Scientific Affairs, Alexander Yuan, Foreign Affairs Officer Multilateral Team
Council on Environmental Quality, DE
Council on Environmental Quality, Horst Greczmiel, Associate Director for NEPA Oversight, DC
David Bernhardt, Department of Transportation
Department of Agriculture Conservation and Forestry, Maine Coastal Program
Department of Health and Human Services, DHHS Environmental Program Manager
Department of Interior, National Park Services, Patrick Walsh, Chief, Environmental Planning and Compliance Branch
Department of Interior, Office of Environmental Policy & Compliance, David Shire, Team Leader, Natural Resources Management
Department of Justice, Natural Resources Section, NEPA Coordinator, Environmental and Natural Resources Division
Department of the Interior, Bureau of Land Management, Division of Decision Support, Planning and NEPA
Department of the Interior, Division of Environmental and Cultural Resources Management, Bureau of Indian Affairs
Department of the Interior, Environmental Policy & Compliance, National Resources Management
Department of the Interior, Land Minerals Management Service
Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Chief Counsel
Department of Transportation, Surface Transportation Board
Director for Import/Export Activities, US Department of Energy
Director, Division of Emergency and Environmental Health Services, Department of Health and Human Services National Center for Environmental Health (CDC)
Ecologist Services Division, U.S. Department of Agriculture
Energy & Natural Resources Committee Office
Environmental Protection Agency, Office of Enforcement and Compliance Assurance
National Marine Fisheries Service-Department of Commerce
National Oceanic and Atmospheric Administration Coast Survey, Andrew Beaver, RI
National Oceanic and Atmospheric Administration, Mary Scott, Marine Habitat Resource Specialist, MA
National Oceanic and Atmospheric Administration, National Marine Fisheries Service Northeast Regional Office, Habitat
Conservation Division, Christopher Boelke, Marine Habitat Specialist, MA
National Oceanic and Atmospheric Administration, National Marine Fisheries Service Northeast Regional Office, Habitat
Conservation Division, Mary Colligan, Assistant Regional Administrator for Protected Resources, MA
National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Assistant Regional Administrator for Habitat Conservation, Peter Colosi, MA
National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Jeff Murphy, Fisheries Biologist, Maine Field Station, ME
National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Northeast Regional Office, Protected Resource Division, Kristen Koyama, Ship Strike Coordinator, MA
National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Program Planning and Integration, NEPA Coordinator, MD
National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Sean McDermott, Fisheries Biologist, MA
Natural Gas STAR, US EPA
NOAA, National Marine Fisheries Service, Fishery Biologist, H. Max Tritt
Office National Oceanic & Atmospheric Administration Department of Commerce
Office of Deputy Undersecretary Defense (Installations & Environment), Department of Defense
Office of Environmental Management, Department of Energy, Dave Huizenga, Senior Advisor
Office of Federal Programs, Assistant Director for Federal Programs, Advisory Counsel, Historic Preservation
Office of the Assistant Secretary of the Army, Tribal and Regulatory Affairs, Chip Smith, Assistant for Environment, DC
Office of the Assistant Secretary of the Navy, Robert Uhrich, Installations and Environment, DC
Office of the Deputy Under Secretary of Defense (Installations & Environment)
Office of the Deputy Under Secretary of Defense, Installation and Environment, Peter Potochney, Director, Basing, DC
Office of the Under Secretary of Defense, Sonny White, DC
Policy Office of the Assistant Secretary of the Navy (EI&E), Environmental Planning and Conservation
U.S. Air Force Basing & Units, Department of Air Force, Department of Defense
U.S. Ambassador to Canada, The Embassy of the United
States of America, David Wilkins, Canada
U.S. Army Corps of Engineers, Jay L. Clement, Sr. Project Mgr., Maine Project Office, ME

Federal Agencies – Continued

U.S. Coast Guard 1st District, Captain Liam Slein, Chief, Prevention Division, MA
U.S. Coast Guard 1st District, Captain Thomas Lennon Chief, Legal Division, MA
U.S. Coast Guard Atlantic Area, Captain Richard Kaser, VA
U.S. Coast Guard Sector Northern New England, Alan Moore, Port Security Specialist
U.S. Coast Guard, BMC James Malcolm, Officer-in-Charge, Station Eastport, ME
U.S. Coast Guard, Captain James McPherson, U.S. Department of Homeland Security, ME
U.S. Coast Guard, Chief, Commander Patrick W. Clark, DC
U.S. Coast Guard, Chief, Operating and Environmental Standards, Michael Blair, DC
U.S. Coast Guard, Ed Wandelt, Chief, Office of Environmental Management, Department of Homeland Security, Commandant (CG-47)
U.S. Coast Guard, Geological Survey Headquarters, Ken Smith, DC
U.S. Coast Guard, Jason Smiley, Lieutenant, MSFO Belfast, ME
U.S. Coast Guard, LCDR Rogers Henderson, DC
U.S. Coast Guard, Maintenance and Logistics Command Atlantic, General Law Branch, Patrick Wycko, VA
U.S. Customs & Border Protection, Environmental Programs Branch
U.S. Customs and Border Patrol, Barry Thompson, ME
U.S. Department of Commerce, Environmental Program Manager, Genevieve Walker
U.S. Department of Commerce, Sloan Rappoport, Senior Policy Advisor, Office of the Secretary, DC
U.S. Department of Energy
U.S. Department of Energy, Harvey Harmon, Director for Import/Export Activities, DC
U.S. Department of Energy, Office of Intergovernmental Affairs, Steve Lerner, DC
U.S. Department of Housing and Urban Development, Environmental Planning Division
U.S. Department of Navy, Assistant Chief of Staff for Installation Management, Attn: Ravin L. Howell, VA
U.S. Department of State, Bureau of Economic, Energy and Business Affairs, Jeffery Izzo, DC
U.S. Department of the Interior, Bureau of Indian Affairs, Eastern Region, James T. Kardatzke, TN
U.S. Department of the Interior, National Park Service, Acadia National Park Service, John Kelly, Park Planner, ME
U.S. Department of the Interior, National Park Service, Dee Morse, Air Resources Division, CO
U.S. Department of the Interior, National Park Service, Roosevelt Campobello International Park, Harold Bailey, Natural Resource and Planning Manager, ME
U.S. Department of the Interior, Office of Environmental Policy and Compliance, Diane Lazinsky, MA
U.S. Department of the Interior, U.S. Fish & Wildlife Service, Moosehorn National Wildlife Refuge, ME
U.S. Department of Transportation, Environmental Policies Team Leader, Camille Mittelholtz, DC
U.S. Department of Transportation, Environmental Policies, Team Leader
U.S. Department of Transportation, Office of Pipeline Safety, DC
U.S. Department of Transportation, Office of Pipeline Safety, Harold Winnie, MO
U.S. Department of Transportation, Office of Pipeline Safety, Mike Schwarzkopf, GA
U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Jeffrey Wiese, Associate Administrator - Pipeline Safety
U.S. Department of Transportation-Office of Pipeline Safety
U.S. Environmental Protection Agency - New England, Robert Varney, MA
U.S. Environmental Protection Agency - New England, Timothy Timmermann, Office of Environmental Review, MA
U.S. Environmental Protection Agency - Office of Federal Activities, Director, DC
U.S. Environmental Protection Agency, Phil Colarusso, Marine Biologist, MA
U.S. Environmental Protection Agency, Region 1, Betsy Higgins, MA
U.S. Environmental Protection Agency, Susan E. Bromm, Acting Director, Office of Federal Activities, DC
U.S. Fish and Wildlife Service, Ecological Services Office, Michael Amaral, Wildlife Biologist, NH
U.S. Fish and Wildlife Service, Lori Nordstrom, ME
U.S. Fish and Wildlife Service, Wende Mahaney, Fish and Wildlife Biologist, ME
U.S. Geological Survey, Department of Interior, National Mail Center
Under Secretary of Defense, Installations and Environment, Michael McAndrew, DC
United State Coast Guard, Commandant Robert Papp
USDA Forest Service, Farm Service Agency
USDA Forest Service-Ecosystem Management Coordination

State Agencies and Elected Officials

State Agences

ME

Department of Environmental Protection, Bureau of Land & Water, Augusta, ME
Department of Environmental Protection, Bureau of Land and Water, Gregg Wood, PE
Maine Department of Conservation, Bureau of Parks Lands, Kathy Eickenberg
Maine Department of Conservation, Don Cameron, Botanist
Maine Department of Conservation, Maine Forest Service, Donald J. Mansius, Director
Maine Department of Conservation, Natural Areas Program, Rachael Ross, Information Manager
Maine Department of Conservation, Scott Ramsay, Director
Maine Department of Economic and Community Development, Thaxter Traffon, Commissioner

State Agencies (ME) - Continued

Maine Department of Environmental Protection, Bureau of Land & Water
Maine Department of Environmental Protection
Maine Department of Environmental Protection, Bureau of Air Quality, Marc Cone
Maine Department of Environmental Protection, Bureau of Land and Water Quality
Maine Department of Environmental Protection, Bureau of Land and Water Quality, Gregg Wood
Maine Department of Environmental Protection, Bureau of Land and Water Quality, Robin Clukey
Maine Department of Environmental Protection, Ed Logne
Maine Department of Environmental Protection, Office of the Commissioner, James E. Dusch
Maine Department of Environmental Protection, Southern
Maine Regional Office, Bureau of Land and Water Quality, Linda Kokemuller
Maine Department of Inland Fisheries & Wildlife
Maine Department of Inland Fisheries and Wildlife, Endangered and Threatened Species Group, Woodcock
Maine Department of Inland Fisheries and Wildlife, Endangered and Threatened Species Group, Phillip DeMaynadier
Maine Department of Inland Fisheries and Wildlife, Region A, Scott Lindsay, Regional Wildlife Biologist
Maine Department of Inland Fisheries and Wildlife, Region B, James Connolly, Regional Wildlife Biologist
Maine Department of Inland Fisheries and Wildlife, Region C, Ron Brokaw, Regional Fisheries Biologist
Maine Department of Inland Fisheries and Wildlife, Region C, Tom Schaeffer, Regional Wildlife Biologist
Maine Department of Inland Fisheries and Wildlife, Region F, Vasco Carter, Regional Wildlife Biologist
Maine Department of Inland Fisheries and Wildlife, Richard Bard, Wildlife Biologist
Maine Department of Labor, Lauren Boyett, Commissioner
Maine Department of Marine Resources
Maine Department of Marine Resources, Brian Swan,
Environmental Coordinator
Maine Department of Public Safety, John C. Dean, State Fire Marshall
Maine Department of Transportation, Environmental Office, Mark Likus
Maine Department of Transportation, Office of Legal Services, Toni Kemmerle, Chief Counsel
Maine Department of Transportation, Richard D. Elder
Maine Emergency Management Agency, Robert S. Gardner, Technical Hazards Coordinator
Maine Energy Resources Council, Beth Nagusky, Director of Energy Independency & Security
Maine Forest Service, Maine Department of Conservation, Bill Beardsley, Commissioner
Maine Historic Preservation Commission, Earle Shettleworth, Jr., Historic Preservation Officer
Maine Historic Preservation Commission, Mike Johnson, Review and Compliance Coordinator
Maine Historic Preservation Commission, State House Station 65, Dr. Arthur Spiess, Sr., Archaeologist
Maine Marine Patrol, Department of Marine Resources, Lt. Alan Talbot
Maine Port Authority, Brian C. Nutter
Maine Port Authority, Kevin Rousseau
Maine Washington County Community College Facilities
Office of State Fire Marshall, Department of Public Safety, Stephen W. Dixon, Sr., Inspector
U.S. Senator Susan Collins
Washington County Emergency Management Agency, Michael Hinerman

Elected Officials

Carol Woodcock, State Office Representative - Bangor,
Office of Senator Susan Collins
Honorable Joseph Brooks, Maine House of Representatives
Kevin L. Raye, State Senator, Maine State Senate
Maitland E. Richardson, State Representative, Maine House of Representatives
Richard W. Rosen, State Senator, Maine House Senate

Local Government

ME

Governor's Energy Office, Kenneth C. Fletcher, Director, Augusta, ME
Maine State Housing Authority

Androscoggin County

Administrator, Town of Durham, ME
Mayor, City of Lewiston, ME
Town of Sabattus, ME
Suzzanne M. Adams, Town Clerk, Town of Sabattus, ME

Cumberland County

Town Manager, Town of Gorham, ME
Town Manager & Clerk, Town of New Gloucester, ME
Jonathan W. Morris, Selectman, Town of Pownal
Philip M. Wentworth, Board of Selectmen, Town of Pownal, ME
Town Manager, Town of Scarborough, ME
Mayor, City of Westbrook
Town Manager, Town of Windham, ME
Donna M. Chapman, Town Council, Windham, ME

Hancock County

Roger Raymond, Town Manager, Town of Bucksport, ME
Town Clerk, Town of Great Pond, ME

Kennebec County

Town Manager, Town of Windsor, ME

Knox County

Pamela Tibert, Town Clerk, Town of Appleton, ME
Town Clerk, Town of Washington, ME

Lincoln County

Clerk & Administrative Assistant, Town of Somerville, ME

Penobscot County

Melissa Doane, Town Manager, Town of Bradley, ME
Gail Kelly, Mayor, City of Brewer, ME
Town Manager, Town of Eddington, ME
Town Manager, Town of Milford, ME
Town Manager, Town of Orrington, ME

Local Government - Continued

Sagadahoc County

Marc Berner, Board of Selectman, Town of Bowdoin, ME
Melanie Page, Town Clerk, Town of Bowdoin, ME
Town of Bowdoin, ME
Kathy Durgin-Leighton, Town Manager, Town of Bowdoinham, ME
David Peppard, Town Manager, Town of Richmond

Waldo County

Municipal Clerk, Town of Frankfort, ME
Evelyn Adams, Board of Selectmen, Town of Frankfort, ME
Town Clerk, Town of Liberty, ME
Board of Selectmen, Town of Liberty, ME
Town Manager, Town of Lisbon, ME
Town Clerk, Town of Monroe, ME
Town Clerk, Town of Montville, ME
Town Clerk, Town of Searsmont
Alice Pearse, Assistant to the Selectmen, Town of Searsmont
Town Manager, Town of Winterport, ME

Washington County

Town Manager & Clerk, Town of Baileyville
Fire Chief, Town of Calais
Police Chief, Town of Calais
Police Chief, Town of Eastport, ME
City of Eastport, City Manager, George Finch
Eastport Port Authority, Chris Gardner, Port Director
Board of Selectman, Town of Perry, ME
Jeanne Guisinger, Board of Selectmen, Town of Perry, ME
Town Clerk, Town of Princeton, ME
Earle Stanhope, Commissioner, Town of Robbinston
Fire Chief, Robbinston Fire Department
First Selectmen Tom Moholland, Robbinston, ME
County Commissioner, Washington County, ME

York County

Town Clerk, Town of Eliot, ME
Mayor, City of Saco, ME

Rockingham County

Town Clerk, Town of Newington, NH

CANADA

Canada - Department of State

Beatrice Soila, Office of Canadian Affairs
Pedro Erviti, Office of Canadian Affairs

Canada - Coast Guard

Nancy Hurlburt, Director, Maritime Services
Ryan Green, Canadian Coast Guard
Sophie Galarneau, Communications Officer, Fisheries and Oceans Canada Communications Branch

Canada - Media

Michael Holmes, New Brunswick, CANADA
Michael Holmes, Senior Editor, CBC Radio

Canada - Environment Canada

Blair Sparks, Manager, National Marine Service Centre
Claude Rivet, Environmental Emergencies - Quebec Region
Jim Abraham, Director General, Atlantic Region, Nova Scotia Regional Headquarters
Ken Hamilton, Regional Director, Atlantic Division, Environmental Protection Branch
Mark Dittrick, Conservation Chair
Michelle Brenning, Director General, Canadian Wildlife Service
Robert Reiss, Environmental Emergencies - Quebec Region
Robyn Whittaker, Senior Program Engineer, Ecological Measures Division
Roger Percy, Atlantic Region
Steve Zwicker, Senior Environmental Assessment Advisor, Environmental Assessment Section, EPOD - Atlantic, Environmental Stewardship Branch

Canada - Department of Intergovernmental Affairs

Jim McKay, Deputy Minister
Lynn MacKay, Senior Policy Advisor, Province of New Brunswick

Canada - Canadian Environmental Assessment

Bill Coulter, Director, Atlantic Office
Yves Leboeuf, Director, Policy Analysis

Canada - Embassy

Ambassador, Michael Wilson, Canadian Embassy, DC
John Stewart, Economic Specialist, The Embassy of the United States of America, Ontario
Richard Rosenman, Energy and Environment, The Embassy of the United States of America, Ontario

Canadian Agencies

Town of St. Andrews, New Brunswick, CANADA
U.S. Consulate General of the USA in Halivax

Canada - Other Interested Parties

Atlantic Salmon Federation, Frederick Whorisky, V.P. Research & Environment
Friends of Head Harbour Lightstation
Jessie Davies, St. Andrews
Joyce Morrell & Janice Meiners
Michael Power, Bayside Port Corporation
Michael R. Power, Canada
Nature Trust of New Brunswick
New Brunswick Tourism Action Group
Peter and Mary Louise Kane, Canada
Premier of Canadian Province of New Brunswick
Rita Raser, New Brunswick
Save Passamaquoddy Bay, Inc.
Shawn Graham, St. Stephen
St. Andrews, Town Council, New Brunswick

Non-Governmental Organizations

American Gas Association, Dave Parker, President, DC
Carmody Marine Consultant, David L. Carmody, ME
Cobscook Bay Fisherman's Association
Cobscook Bay Fisherman's Association, Harry Shain, Sr., Chair, ME

Non-Governmental Organizations – Continued

Cove Brook Watershed Council, Gayle Zydlewski, President, ME
Humane Society of the United States, Wildlife Trust, DC
Machias/East Machias River Watershed Councils, Bill Cherry, Coordinator, ME
Maine Advocacy Center (Conservation Law Foundation)
Natural Resources Council of Maine, Dylan Voorhees, Energy Project Director, ME
Pan AM Railways, Sydney Culliford, MA
Sierre Club, Vivian Newman, ME
St. Croix International Waterway Commission, Lee Sochasky, Executive Director, ME
The Nature Conservancy, Barbara Vickery, Director of Conservation Programs, ME
The Wilderness Society, Pete Morton, Ph.D., Resource Economist, CO

Other Interested Parties

Aimee and Michael Morrell
Alan Brooks, Quoddy Regional Land Trust, ME
Alva Mesman, ME
Andrew L. Dannengert, MD, MPH, Center for Disease
Control and Prevention, GA
Arthur A. Ransome, CH IV International, MD
Arthur E. Gelber, North East Energy Development Company
LLC, TX
Barry Woolaver, ME
Bernard J. Lukco, OH
Bill Kapaldo, ME
Bluebird Rauch
Bonnie Stronach, ME
Calais Fire Department
Captain Gerald S. Morrison, Master Mariner, Eastport Pilots
USA, ME
Captain Gerald S. Morrison, ME
Carol P. Bryan, ME
CES, Inc.
CH IV International
Cobscook Bay Resource
Danny and Sheila Stanhope, MN
Darrell and Mavis Warren, ME
Darren and Jamie Morrell
David and Denise Koehne, ME
David Jenkins, MA
DECD
Dennis and Virginia Sterner, ME
Dennis Ryan, ME
Donald Soctomah, ME
Douglas Newman, ME
Ed Seeley, ME
Edward Gomes, MA
Edward Lewis Trust, FL
Edward S. O'Meara, Jr., ME
Elaine, Bonny and Scott Merryfield, ME
Enviromet, LLC
Erik Squire, ME
Eugene P. Weldon, The Lane Construction Corporation, ME
Frank Ohara, ME
Fred Hartman, ME
Hal and Amy Mann, VA
Harold Smith, ME
Harold W. Clossey, Sunrise County Economic Council, ME
Healy & Aldrich, Inc.
James A. Hamilton, PE, CLF Ventures, Inc.
James and Linda Raymond, ME
James Morris, ME
Janet and Thomas Parks, FL
Jeffrey & Leah McLean, ME
Jessica Welch, ME
Joe Moholland, VA
John and Pat Owen, ME
John and Wendy Kruger, ME
John Scott, Tetra Tech EC, MA
John Wentworth and Susan Cox, ME
Joseph and Pina Pilaro, ME
Joseph Footer and Nicole Footer
Kathy and Blair Moholland, ME
Kelli Toole, ME
Kevin Lane, ME
Kevin Morrell, ME
Kirk Maenhout, ME
Linda Howe, ME
Linda Newcomb, Harris Point Shore Cabins and Motel, ME
Louis Paul, ME
Marc Rhode, ME
Maritime & Northeast
Mark and June Kennedy, ME
Marshall and Ruth Lucas, ME
Mary Albright, Pierce Atwood, ME
Matthew Manahan, ME
Maynard and Rita Morrison Trust, ME
Merrill C. Morris, Jr., ME
Michael Brown and Valerie Lawson, ME
Pat Murphy, IL
Philip Ahrens, Pierce Atwood, ME
RADM Bryan W. Flynn, MD
Raymond Faulkner and Lana Perkins, ME
Richard Mingo, ME
Ricky and Dorothy Muncey, ME
Rita Fraser, C/O Shems Dunkiel Kassel & Saunders PLLC, VT
Robert Wyatt, Downeast LNG Inc., DC
Rosemary E. Bradshaw, PA
Roy Knights, ME
Save Passamaquoddy Bay from LNG
Shirley St. Pierre, ME
Sidney Unobsky Trust, CA
Stanley Kielb, ME
Susan Woodman, ME
Tetra Tech Inc., Nathalie Schils, Environmental Scientist
Tetra Tech, Inc., Sean Sparks, Biologist
Todd and Sarah Walters, AK
Tom McLaughlin, ME
Verizon New England
Walter Loring, ME
Warren and Thelma Moholland, ME
William and Vicki McLaughlin, ME
William J. Schneider, Maine Attorney General, ME
WRC Pipeline

Labor Unions
Bruce King, Carpenters Local Union 1996, Augusta, ME

Libraries
Appleton Public Library
Bangor Mental Health Library
Baxter Memorial Library
Belfast City Free Library
Bowdoinham Public Library
Bucksport Library
China Library
City of Brewer Library
Colonel Black Library
Dorothy W Quimby Library
Dyer Library
Ellsworth City Library
Freeport Community Library
Gardiner Public Library
Gibbs Library
Hadley Parrot Health Sci Library
Isaac F. Umberhine Public Library
Ivan O. Davis-Liberty Library
Kennebunk Free Library
Langdon Public Library
Lewiston Public Library
Lisbon Falls Community Library
Martha M. Doore
Mildred Stevens Williams Memorial Library
Monroe Community Library
New Gloucester Public Library
Old Town Public Library
Orono Public Library
Orrington Public Library
Portsmouth Public Library
Princeton Public Library
Raymond H Fogler Library
Scarborough Public Library
School Administrative District No 34
Searsmont Town Library
Somerville Town Library
Susan Farrell Caust Memorial Library
Thorndike Library
Topsham Public Library
Waldo Pierce Reading Room
Walker Memorial Library
Warren Memorial Library
Weeks Public Library
William Fogg Library
Windham Public Library
Winterport Memorial Library
Woodland Public Library

Newspapers
American Journal
Bangor Daily News
Bangor Daily News
Bangor Daily News
Belfast -Searsport Republican Journal
Brunswick Times Record
Camden Herald
Capital Weekly
Community Leader
CoudyNews.com
Dover Community News
Eagle-Tribune
Foster's Daily Democrat
Kennebec Journal
Knox County Courier-Gazette
Lakes Region Weekly
Lewiston Sun Journal
Lincoln County News
Machias Valley News Observer
Maine Biz Magazine
New Gloucester Independent
Northern Forecaster
Portland Press Herald
Portsmouth Herald
Quoddy Tides
Rockland Free Press
Scarborough Leader
Southern Forecaster
St. Croix Printing & Publishing Co. Ltd.
The Calais Advertiser
The Current
The Potter Leader Enterprise
The Quoddy Tides
The Saint Croix Courier
The Sipayik Newsletter
Tri-County Enterprise
Union Leader
Waldo Independent
Windham Independent
York County Coast Star

Tribal Nation Elected Officials and Management
Bonnie Newsom, Tribal Historic Preservation Officer,
Penobscot Indian Nation, Indian Island Reservation, ME
Brenda Commander, Tribal Chief, Houlton Band of Maliseet Indians, ME
Clem Fay, Fisheries Manager, Penobscot Indian Nation,
Indian Island Reservation, ME
Dale Mitchell, Passamaquoddy Tribe at Pleasant Point Reservation, ME
Donald Soctomah, Tribal Historic Preservation Officer, Passamaquoddy Tribe at Indian Township Reservation, ME
George Paul, Aroostook Band of Micmacs, ME
James Sappier, Chief, Penobscot Indian Nation, Indian Island Reservation, ME
John Banks, Director Department of Natural Resources,
Penobscot Indian Nation, ME
Mark Altvater, Passamaquoddy Tribal Council, ME
Passamaquoddy Tribe of Indian Township
Passamaquoddy Tribe, ME
Richard Stevens, Governor, Passamaquoddy Tribe at Indian Township Reservation, ME
Steve Crawford, Passamaquoddy Tribe at Pleasant Point Reservation, ME

Service List
Alexander R. Hoar, U.S. Department of Interior
Andrew Raddant, Regional Environmental Officer, U.S. Department of the Interior, Office of Environmental Policy and Compliance
Andrew Tittler, Attorney - Advisor, U.S. Department of Interior
Angus McPhail, Passamaquoddy Lobstermen Association
Art MacKay, Executive Director, St. Croix Estuary Project
Ashley Barret, Regulatory Affairs, M&N Management Company
Bruce Kiely, Partner, Baker Botts LLP
Captain Robert J. Peacock, II, Quoddy Pilots USA
Carol MacLennan, State Attorney, Maine Public Utilities Commission
Christopher Barr, Attorney, Post & Schell, P.C.
D. Morgan, Baker Botts LLP
Darrell Paul, Union of New Brunswick Indians
David Wochner, Sutherland Asbill & Brennan LLP
Dean Girdis, President, Downeast Pipeline, LLC
Dean Girdis, President, Downeast Pipeline, LLC
Diane Barnes, City of Calais, ME
Dolores Chezar, KeySpan Energy Delivery Companies
Frank Seeley, ME
Frederick Whoriskey, Chairman of the Board, Huntsman Marine Science Center, Canada
G. Mark Cook, Baker Botts LLP
Gary Lee Guisinger
Gina Brooks, Director, St. Mary's First Nation
Gretchen Fitzgerald, Sierra Club of Canada
James D. Seegers, Vinson & Elkins LLP
Joel Stanhope, Passamaquoddy Lobstermen Association
Jonathan Southern, City Manager, City of Eastport
Joseph and Lea Sullivan, Katie's on the Cove
Joseph F. McHugh, Director, Rates & Regulatory Affairs, M&N Management Company
Kenneth Maloney, Cullen and Dykman
Ki McClennan, Nulankeyutmonen Nkihtahkomikumon
Kim Clark, John & Hengerer
Kimberly Cook, Cook & Associates P.A. LLC
Linda Newcomb
Lisa Tonery, Fulbright & Jaworski LLP
Maine Public Utilities Commission, Secretary
Margaret O. McGarvey
Mark Dittrick, Conservation Chair, Sierra Club of Canada, Atlantic Canada Chapter
Mary Bassett, Passamaquoddy Pleasant Point Reservation
Michael and Cathy Footer, ME
Michael V. Gabel, Mobil Natural Gas, Inc.
Norman R. Dube, Fisheries Scientist, Maine Atlantic Salmon Commission
Norville T. Getty, Policy Advisor, Union of New Brunswick Indians
Nulankeyutomonen Nkihtahkomikumon, C/O Mary Bassett
Paul and Suzanne Crawford, Haines-Crawford & Associates
Paul Forshay, Attorney, Sutherland Asbill & Brennan LLP
Paul LePage, Governor, Maine Office of the Governor
Port Director, Eastport Port Authority
Rebecca Boucher, VT
Rick Doyle, Governor, Passamaquoddy Tribe at Pleasant Point Reservation
Robert & Linda Godfrey, Save Passamaquoddy Bay
Robert Godfrey, Old Sow Publishing
Roland and Kathy Chambers, ME
Ronald Albert Shems, ESQ
Ronald Beckwith, Superintendent, Executive Secretary, U.S. Department of the Interior, National Park Service, Roosevelt
Campobello International Park
Ronald Moore, Mobile Natural Gas, Inc.
Roxane Maywalt, Counsel, National Grid USA
Sherri Booye, Skadden, Arps, Slate, Meagher & Flom LLP
Stacy Dimou, ME
Stephen Swartz, The Humane Society of the United States, Wildlife Land Trust
Steven E. Hellman, Associate General Counsel, M&N Management Company
Ted Gehrig, President and COO, Mill River Pipeline, LLC
Terrie McNulty, The Humane Society of the United States, Wildlife Land Trust
U.S. Senator Olympia Snowe
Vera Francis, Nulankeyutmonen Nkihtahkomikumon

Landowners
Aaron James, ME
Ada Taber, ME
Alden and Donna Mingo, ME
Andrew and Donna Marion, ME
Anna Writer and Elizabeth Kleinfield, FL
Anthony Cilwa, SC
Anthony DiLeo, ME
Arthur and Bertha Johnson, ME
Arthur Mingo, c/o Alden Mingo, ME
Baileyville Utilities District, ME
Barbara Barnes, ME
Bernard and Gail Carter, MA
Bernard Johnson, ME
Betty L. Gardner, ME
Bill and Pal Brett
Billy Howard, ME
Brandon Harriman, ME
Brian Altvater, ME
Calvin James, ME
Carl, Peter and Calvin Goodwin, CT
Carol Woodcock, U.S. Senator Collins Office, ME
Caroline Michalicki and Dick Oswell, FL
Charles & Laurie Slavin, ME
Chris Goodwin, ME
Chris Heinig, ME
Craig Roderick, ME
Cynthia Adams, ME
Dale S. Perry, ME
Dale Wing, ME
Dalton B. Dwelley, ME
Dana Cookson, ME
Daniel Cyr, ME
Daniel Szatkowski, ME
Darrel and Jean Elsemore, OH
Darren and Stephanie Ireland, ME
David and Amy Gillis, ME
David and Deborah Johnson, ME

Landowners - Continued

David and Estelle Holloway
David and Glenna Ferris, ME
David Dean and Duane Carlow, ME
David Turner, President, Perry Improvement Association, ME
Debra Taber, ME
Diane Bradstreet and Mike Conner, ME
Direct TV
Domtar, Inc.
Donald and Heather Sargent, ME
Donald and Lisa Leighton, ME
Donald Webster, FL
Doris Mathewson, ME
Dorothy Johnson, ME
Dorothy Linda Richardson, ME
Dr. Christopher Hayward, ME
Eastern Lake LP
Edith P. Murphy, IL
Edmund and Lucinda Delmonaco, ME
Edmund and Susan Ferreira, ME
Edward and Kathryn Mekelburg, ME
Edward Kokoszka and Glenda Frank, ME
Edwina K. Howland, ME
Egil Straujups, MA
Elaine McPhail, ME
Eleanor Clark, ME
Eric and Beth Hinson, ME
Ernest & Eva Johnson and Judy Gillman, ME
Exxon Bohanons, ME
Fernand Roussel, ME
Frank and Mary DiMarco
Gary Small, ME
George and Nancy Fennell, Omega Development Groups, ME
Gerry Morrison, ME
Gregg and Patricia Brooks, CT
Guilford Trans Industries, Inc.
Harold Smith, ME
Heirs of Georges A. Day, Sr., c/o Julia Burgess, ME
Heirs of Raymond Forer, ME
Heirs of Wellington James, ME
Herm Gadway
Howard and Maryann Duvall, ME
Irving Oil Corporation
ISWASCW Limited Partnership
J. Patrick Tielborg, Pipe Line Contractors Assoc., TX
J.D. Lormand, Exec. Director, Rocky Mountain P/L Construction Assoc., LA
J.P.S. Equipment Company
James and Debra Morrell, ME
James Herlihy, ME
James McLaughlin, ME
Jane MacDonald, ME
Janice Meiners, ME
Jay and Karen Hinson, ME
Jean Holmes, CT
Jean Johnson, Downeast LNG Project, ME
Jeanne Schrumpf, ME
Jeff Hummel & Mary Jane Sylvester, NJ
Jeffrey and Martha Pratt, ME
Jerry Smith, ME
Jesse Demmons, ME
Joe and Margaret Harding, ME
John and Judith Hawkes, ME
John and Mary McDonald, ME
John and Rhonda Chambers
John Brooks, ME
John Churchill and Jane Eaton, ME
John E. Hiland, TN
John Haley, ME
John J. Eagan
John J. Steadman, ME
John Johnson, CT
John McGovern, ME
John R. Hanson, ME
John S. Hornbrook, ME
John W. Wardwell, Lane Construction Corp., ME
Jon Stanhope, ME
Joseph & John Babb, MO
Joseph Edward Johnson, CT
Joseph Pressley, ME
Justin R. Flood, ME
Karen Flagg, ME
Kathleen Byron, ME
Kenneth J. Vaillancourt, ME
Kenneth W. Bayliss
Kevin Ham and Billie Jo Ham, ME
Kimberly Janes, ME
Lakeville Shores
Lawrence Elliott, CT
Leo & Joan Blais, ME
Lewis and Renee Cheverie, CT
Lincoln Company
Linda Pagels Wentworth
Lou Ann Haley, ME
Louisana Pacific Corp.
Lula Wieland, ME
Magnar Rambjor, ME
Maritimes and Northeast Pipeline, L.L.C., c/o Duke Energy, Attn: Lloyd Kelly, TX
Mark and Arlene Wren, ME
Mark and Susan Olson, ME
Marshall and Donna Hennequin, ME
Martin Cook, ME
Mary Baade, NY
Merrill, Gregory and Deanna Brooks, ME
Michael and Lori Carr
Michael and Shelly Bodkin
Michael Foggia, Baring Plt. Volunteer Fire Department Inc., ME
Michael Pottle, ME
Mike and Lori Ellis, ME
Mr. & Mrs. Fred Donahue
Nancy Lucas, ME
Nature Conservatory
Neal and Darlene Bohanon, ME
Norman and Barbara Mylen, ME
Norman and Lisa Brooks, ME
Norman and Mary L. Burpee
Norman and Sylvia Day, ME

Landowners - Continued

Olive and Thomas Bentum, ME
Omega Development
Patrick and Elaine Driscoll, ME
Patrick Burke, ME
Paul and Sarah Strickland, MN
Paula McLaughlin and Carl McGouldrick, ME
Peter Erik Garland, ME
Philip Beckett, Sr., ME
Philip W. and Eva Beckett, ME
Prout Enterprises
Prout Enterprises, ME
Ralph Markarian, PA
Randy and Therese McCormick, ME
Raymond Heffler, ME
Raymond R. Laliberte, CA
Rebecca Cookson, ME
Resource Systems Engineering
Richard and Katherine Berry, ME
Richard and Lucy Carver, AZ
Richard and Susan Mingo, ME
Richard Mingo, ME
Robert and Barbara Henkel, ME
Robin Bouchard, ME
Rodney Brent Scott Heirs, ME
Roger and Margaret Alexander, ME
Roger and Nancy Dumont, ME
Roger McIver, ME
Ronald W. Wallace, ME
Ronna M. Pisha, ME
Rosella Lagerquist, ME
Ruth Maloney, ME
Ryand & Cindy Goodwin, CT
Sandbox Materials, Inc.
Sandra Johnson, ME
Scott A. Leach, The Lane Construction Corporation, ME
Scott Hallowell, ME
Scott Johnson, MA
Sharon L. Warner, TN
Sheila Lambert Merrill, ME
Shelly MacDougall, ME
Sherman McCarter Trust, c/o E. Tyler, CA
Sherry Campbell, ME
Shery King, ME
Spendic Club, Inc.
Stanley and Eleanor Johnson, MA
Stanley Morrell, ME
Sunrise Sand & Gravel
Terry A. Tracy, ME
Theriault, Rowland, North Billerica, MA
Thomas and Katharine L. Kelley, ME
Thomas Brennan & Alison Kritzker, ME
Thomas Dicenzo, Inc., ME
Thomas Driscoll, ME
Thomas J. McLaughlin, AZ
Thomas Lawless, WA
Thomas Robb, ME
Thomas Webster, ME
Tom and Cindy Moholland, ME
Trond Saeverud and Joan Siem, ME
Troy and Luicha Case, ME
Trudy and Darron James, ME
Typhoon, LLC
V.L. Tammaro Oil Co., Inc.
Valmore F. and Laurel A. Denine, Jr., ME
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Waverly A. Moore, FL
Wayne and Anita Johnson, ME
Wayne and Peggy Coleman, ME
Wayne Diffin and Janie Honeck, ME
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William and Sandra Pulk, ME
William DelMonaco, Jr., ME
William Roekrich, ME
Woodland Baptist Church
Woodland Pulp, LLC

Appendix B References

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